STATE OF INDIANA

Mitchell E. Daniels, Jr.
Governor

STATE BUDGET AGENCY
212 State House
Indianapolis, Indiana 46204-2796
317-232-5610

Charles E. Schalliol
Director

May 16, 2006

Paul Dubenetzky
Assistant Director
Office of Air Quality
Indiana Department of Environmental Management
100 North Senate Avenue
Indianapolis, IN 46204
Dear Mr. Bolin:

Pursuant to the provisions of Executive Order 2-89 and Budget Agency Financial Management Circular 89-1, the State Budget Agency has reviewed the proposed changes to rule 326 IAC 24-1, 2 and 3 (LSA# 05-117 which you submitted to the State Budget Agency on March 31, 2006.

After reviewing the proposed rule, the recommendation of the State Budget Agency is that the rule changes be approved.

If you have any questions concerning this action, please contact your budget analyst or Gayle Pierson at 232-5610.

Sincerely,

Charles E. Schalliol
Budget Director pm

CES/GP

STATE OF INDIANA

Mitchell E. Daniels
Governor

OFFICE OF MANAGEMENT & BUDGET

212 State House
Indianapolis, Indiana 46204-2796
317-232-5610

Charles E. Schalliol
Director

May 19, 2006

Paul Dubenetsky
Assistant Director,
Office of Air Quality
Indiana Department of Environmental Management
100 North Senate Avenue
Indianapolis, IN 46204

Dear Mr. Dubenetsky,

Pursuant to the provisions of IC 4-3-22-13, the Office of Management & Budget has reviewed the proposed rule IAC 24-1, 2, and 3 (LSA #05-117) which you submitted to the State Budget Agency on March 31, 2006.

After review of this proposed rule and the fiscal impact analysis, the recommendation of the Office of Management & Budget is that the rule be approved.

If you have any questions concerning this action, please contact Tony Armstrong, Deputy at 232-5604 or Joe Rice, Budget Analyst at 232-5629.

Sincerely,

Charles E. Schalliol
Director, Office of Management & Budget

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We make Indiana a cleaner, healthier place to live.

Mitchell E. Daniels, Jr.
Governor

Thomas W. Easterly
Commissioner

100 North Senate Avenue
Indianapolis, Indiana 46204
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MEMORANDUM

To: Charles E. Schalliol, Director
Office of Management and Budget

From: Paul Dubenetzky, Assistant Commissioner PD
Office of Air Quality

Date: March 31, 2006

Subject: Analysis of Fiscal Impact of New Rules Concerning Nitrogen Oxide (NO_x) and Sulfur Dioxide (SO_2) Emissions from Fossil fuel-fired Power Plants; LSA #05-117

The Department of Environmental Management (IDEM) is submitting these draft rules for your economic impact analysis under IC 4-22-2-28, IC 13-14-9-5, and IC 13-14-9-6. The fiscal impact statement referred to in IC 4-22-2-28(e) is due not later than twenty-one (21) days before the proposed date of preliminary adoption of the proposed rule. IDEM plans to present these rules to the Air Pollution Control Board on June 7, 2006. Therefore, a fiscal impact statement is due from Office of Management and Budget on May 16, 2006. The following information is provided for your analysis:

1. Clean Air Interstate Rule (CAIR) Cost Impact Analysis.
2. The second notice of comment period which contains the draft rule published in the Indiana Register on December 1, 2005.

The costs presented in this fiscal impact analysis (FIA) are not above and beyond what would incur from the federal program and are based on the draft language in the Second Notice. The department will update the FIA based on any changes in the rule between preliminary and final adoption.

Rule summary: IDEM has developed draft rule language for new article 24 that contains three new rules 326 IAC 24-1, CAIR Nitrogen Oxides (NO_x) Annual Trading Program, 326 IAC 24-2, CAIR Sulfur Dioxide (SO_2) Annual Trading Program, 326 IAC 24-3, CAIR Nitrogen Oxides (NO_x) Ozone Season Trading Program, and new rule 326 IAC 10-4-16.

Background: On March 10, 2005, the USEPA signed the federal CAIR to achieve substantial reductions of NO_x and SO_2 emissions from fossil-fuel-fired power plants (EGUs) in twenty-eight (28) states (including Indiana) and the District of Columbia for the purpose of reducing interstate transport of air pollution. CAIR establishes 3 cap and trade programs with two phases with declining emission caps that build upon the existing Acid Rain program and NO_x SIP Call trading program. Indiana adopted a state rule to implement the NO_x SIP Call in June of 2001 reducing ozone season emissions of NO_x from EGUs and large industrial non-electric generating units (non-EGUs) (326 IAC 10-4). The three (3) trading programs in CAIR include an ozone season NOx program that will replace the NOx SIP Call trading program, a new annual NOx trading program, and an annual SO2 trading program that builds upon the existing Acid Rain program.

IDEM is proposing to include the non-EGUs from the NOx SIP Call ozone season trading program in 326 IAC 10-4 in the CAIR ozone season NOx rule. This will allow the non-EGUs to continue trading with EGUs and not be restricted to trading among Indiana non-EGUs. The total allowances for the non-EGUs are added to the CAIR NOx ozone season trading budget and additional reductions are not required for these sources. The draft rule adds 326 IAC 10-4-16 to sunset parts of the NOx SIP call for transitioning to CAIR.

Indiana has until September 11, 2006, to submit a state implementation plan (SIP) to USEPA implementing CAIR. However, USEPA has proposed a streamlined approval process for states that follow the USEPA model trading program rules and make limited changes to it that extends the SIP submittal date to March 31, 2007. IDEM is planning to submit a SIP to USEPA by March 31, 2007. States that do not submit a SIP will be subject to a federal implementation plan that USEPA has developed.

Sources regulated by CAIR are as follows:

<u>EGUs (14 utilities – 37 power plants)</u>
1. American Electric Power (AEP) - (Rockport, Tanners Creek)
2. Cinergy - (Wheatland, Cayuga, Connersville, Edwardsport, Gallagher, Gibson, Henry County, Wabash River, Vermillion Energy, Noblesville)
3. Dayton Power & Light Energy LLC (DPL) - (Montpelier)
4. Dominion State Line Energy - (Stateline)
5. Hoosier Energy REC - (Frank E Ratts, Merom, Worthington, Lawrence County Station)
6. Indiana Municipal Power Agency (IMPA) - (Anderson, Richmond)
7. Indiana-Kentucky Electric Corp. - (IKEC) (Clifty Creek)
8. Indianapolis Power & Light (IPL) - (Elmer W Stout, Georgetown, H T Pritchard, Petersburg)
9. Mirant - (Sugar Creek)
10. NiSource - (Bailly, Dean H Mitchell, Michigan City, Schahfer)
11. PSEG Power - (Lawrenceburg Energy Facility)
12. Richmond Power & Light (RPL) - (Whitewater Valley)
13. SIGECO - (A B Brown, Broadway, F B Culley, Warrick)
14. Whiting Clean Energy - (Whiting Clean Energy)

<u>Non-EGUs (8 sources)</u>
1. American Electric Power-Rockport
2. BP Whiting Business
3. Citizens Thermal Energy
4. Mittal Steel Indiana Harbor
5. New Energy
6. Portside Energy

7. Purdue University
8. US Steel Gary Works

IDEM hereby requests that you review the cost data contained in our analysis and prepare a fiscal impact statement per IC 4-22-2-28 by May 16, 2006. Thank you for your assistance, and if you have any questions, please contact me at 232-8222 or Kathy Watson, OAQ Branch Chief, at 233-5694.

Indiana Department of Environmental Management
Clean Air Interstate Rule
Cost Impact Analysis
(March 31, 2006)

Introduction and Summary

This document presents the cost impact of the proposed Clean Air Interstate Rules (CAIR), 326 IAC 24-1, 326 IAC 24-2 and 326 IAC 24-3. The rules affect the fossil-fuel-fired large utility boilers (with nameplate capacity of more than 25 MW), known as "EGUs", and large industrial boilers (with maximum design heat input greater than 250 million Btu/hr), known as "non-EGUs". Rules 326 IAC 24-1 and 326 IAC 24-2 regulate annual nitrogen oxides (NOx) and sulfur dioxide (SO2) emissions from EGUs and the rule 326 IAC 24-3 regulates ozone season NOx emissions from EGUs and non-EGUs. The rules set emission budgets for nitrogen oxides (NOx) and sulfur dioxide (SO2), allow compliance by emissions trading, and require demonstration of compliance by emissions measurement. The rules will be implemented in two phases. The NOx rules Phase I will be implemented in the year 2009 and the Phase II in 2015. The SO2 rule Phase I will be implemented in the year 2010 and the Phase II will be implemented in the year 2015.

As noted above, the rules affect industrial and utility boilers, therefore, the impact of CAIR on these two source sectors is presented. The cost estimate for the non-EGUs is based on their NOx allowances, projected emissions and the projected allowance prices. The cost estimate for the EGUs is based on the Integrated Planning Model (IPM). The model represents economic activities in key components of the energy markets: fuel markets, emission markets, and electricity markets. The applications of IPM have included capacity planning, environmental policy analysis and compliance planning, wholesale price forecasting, and asset valuation In this case, IPM was used to project which utility units would add emission controls under the emissions trading program.

In September 2005, the department performed a preliminary cost analysis and made it available to stakeholders for comments and suggestions. (1) The analysis was performed using the IPM analysis the USEPA used in its CAIR regulatory impact analysis. The USEPA discussed the cost and economic impacts of the CAIR in its Federal Register Notice of Rulemaking (70 FR 25162, May 12, 2005) and provided more details in its regulatory impact analysis document. (2) The costs were estimated for the year 2015, the compliance date for Phase II of CAIR. This included the cost of retrofit controls and emissions trading (i.e., the net cost of buying /selling credits). Since the utilities currently have continuous monitoring systems in place to measure emissions, the department estimated that the proposed rules will not impose an additional cost for emissions monitoring. The costs were estimated as incremental to the existing federal and state requirements such as the federal Acid Rain program and the NO_X SIP Call rule. These requirements will be referred to as the "basecase" requirements in this document. In February 2001, the Legislative Services Agency prepared the fiscal impact statement for the Indiana NOx SIP Call rule 326 IAC 10-4. (3)

In November 2005, the department received comments from stakeholders on its cost analysis.[4] The Indiana Energy Association (IEA) along with several non-member companies, collectively known as the Indiana Utility Group (IUG), commented on the assumptions used in the USEPA IPM and submitted its own IPM based cost analysis. [5] The commentors also suggested that the costs should be based on a longer time horizon and should include the costs of additional requirements that the CAIR may impose, such as, fuel-switching, switch in electricity generation and the additional electricity generating capacity. Also, the commentors suggested that the existing post-combustion NOx controls, which were installed to meet the NOX SIP Call ozone season limits, may have to be operated outside the ozone season, to meet the more restrictive CAIR NOx requirements. There was no comment on the emissions monitoring costs.

The department has reviewed the above comments and suggestions and has found it logical to incorporate them into its cost impact analysis. The expenditure on the retrofit controls is likely to start before the CAIR Phase I implementation date and continue as emission limits become tighter. Therefore, the department is presenting the cost impact for a broader time period, 2007 to 2022. It will be seen in the "Methodology" and the "Results" sections, that CAIR is projected to impose additional requirements mentioned above. The IUG projections for key parameters (such as, the electricity load growth, fuel prices and pollution control costs) are higher than the USEPA projections. The department believes that it is not unusual for these projections to vary from one source to the other. The USEPA in its Regulatory Impact Analyses (RIA) for the CAIR has analyzed the differences in its and the Energy Information Administration's (EIA) projections in a sensitivity analysis.[2]

In its RIA for the CAIR, USEPA's electricity load growth projection was 1.6% a year as compared to the EIA's projection equal to 1.8% a year. The EIA fuel prices were higher by \$0.25/mmBtu, \$0.42 /mmBtu and \$0.38/mmBtu for the years 2010, 2015 and 2020, respectively. USEPA analyzed these variations in a sensitivity analysis. The department is presenting the costs as a range under two scenarios: Scenario #1 (IDEM) and Scenario #2 (IUG). In addition, the State Utility Forecasting Group (SUFG), located at Purdue University, Indiana, has analyzed the impact of the EGUs costs for both the scenarios on the electricity rates on behalf of the Indiana Utility Regulatory Commission (IURC) at IDEM's request.

The department will revise the cost estimates between preliminary and final adoption of the rule, if necessary, to take into account any changes in the final rule and will share that update with stakeholders. The costs are summarized in Table 1 below and provided in greater detail in Tables 2, 3 and 4. The methodologies and results are discussed in detail in the next few sections. The cost spreadsheets are contained in Appendices A and B, respectively, for the IDEM and IUG, and the State Utility Forecasting Group (SUFG) analysis of the impact on electricity rates is included in Appendix C.

Table 1: CAIR Cost Summary
(Costs are in million dollars; expressed in 2005 dollars)

	IDEM (Scenario 1)			IUG (Scenario 2)		
Time interval	I	II	III	I	II	III
Projection years	2008-2012	2013-2017	2018-2022	2007-2013	2014-2017	2018-2022
EGUs						
Retrofit controls						
Description	3 SO2 scrubbers	12 SO2 scrubbers; 10SCRs; 2SNCRs	17 SO2 scrubbers, 10SCRs, 2SNCRs	11 SO2 scrubbers	11 SO2 scrubbers; 2 SCRs	13 SO2 scrubbers; 6 SCRs
Capital cost	413	1,493	1,853	1,492	1,689	2,296
Annual cost	95	329	406	292	322	424
Total annual cost (includes all costs)	571	747	906	815	1,021	899
Impact on electricity rates	**5.16%**	**5.97%**	**6.34%**	**6.44%**	**8.55%**	**7.63%**
Non-EGUs						
Annual cost	(5)	(6)	(6)	(5)	(6)	(6)
Net annual cost	566	741	900	810	1,015	893

Note: Retrofit controls and costs in each time interval are cumulative of the previous time interval. Non-EGU costs are negative as revenue is projected from the sale of allowances. SCRs (selective catalytic reduction systems) and SNCRs (selective non-catalytic reduction systems) are post-combustion NOx controls.

Electricity Generating Units

Methodology

Both IDEM and IUG used the IPM in their cost analyses. The IPM, developed by ICF Consulting, Inc., is a multi-regional, dynamic, deterministic linear programming model of the US electric power sector. The model has evolved over a number of years, for example, the 2002 version 2.1 was updated in 2003 as version 2.1.6, which was further updated in 2004 as version 2.1.9. The details can be found in Reference #6.

The model requires input parameters that characterize the US electric system, economic outlook, fuel supply and air regulatory framework. The model has the capability of producing a broad range of outputs, such as, capacity additions and retirements, capacity prices, wholesale electricity prices, power production costs, fuel consumption, fuel prices, allowance prices and emissions (NOx, SO2, CO2, and mercury).

Both IDEM (based on USEPA's IPM runs) and IUG used the IPM version 2.1.9 in their cost estimates. However, IUG's projections for several key parameters are different than those of IDEM. The variations are due to the differences in assumptions and source of data. The IUG assumed an average electricity load growth equal to 1.77% for the period 2007-2020 as compared to the USEPA assumption equal to 1.55%. The IUG estimate is based on the EIA's Annual Energy Outlook (AEO) 2005 and the North American Electric Reliability Council (NERC) forecasts. The USEPA assumption is based on the AEO 2004 sales forecasts, adjusted for reduction in electricity consumption due to voluntary programs operated by the Department of Energy and the USEPA. The IUG pollution control capital costs are 60% to 100% higher than the USEPA assumptions. The IUG projections are based on the market data and the experience of its members, in particular, with the post-combustion NOx controls, such as selective catalytic reduction systems (SCRs) and selective non-catalytic reduction systems (SNCRs), installed in Indiana in response to the NOx SIP Call. The USEPA projections are based on the engineering equations and cost factors developed from surveys. The IUG fuel cost projections are 23% to 47% higher than the USEPA. The IUG estimates are based on the AEO 2005 forecasts and market data, while the USEPA data are based largely on the AEO 2003 forecasts.

In addition, IUG used an updated version of the existing and committed units' database. This database, also known as the National Electric Energy Data System (NEEDS), is a repository of information on the existing and planned-committed units. The updates included corrections to the capacities and the pollution control systems. The accuracy of this database affects the compliance decisions and hence the emissions and the costs. The IUG "hardwired" SO2 scrubbers in its analysis according to the following schedule of IPM model years: 2005, 2006, 2007, and 2008 = firmly planned units plus known Indiana units; January 2009 = firmly planned units plus model determined; January 2010 and beyond = announced plus model selected.

The total CAIR costs include the following cost items:

1. Retrofit control cost
2. Existing and basecase projected post-combustion NOx controls, non-ozone season, variable O&M cost
3. Emissions trading cost
4. Fuel-switching costs
5. Switch-in-electricity generating cost
6. Additional electricity generating capacity cost

All costs are expressed in 2005 dollars ($). The USEPA costs are in 1999 $; they were adjusted to 2005 $ using an inflation factor equal to 1.20. This factor was developed by the department by referring to the Chemical Engineering Plant Cost Index.

The retrofit controls costs include the capital and the annual fixed and variable operation and maintenance (O&M) costs of the control equipment. These costs were estimated for the controls projected by IPM. The capital costs were estimated by multiplying the capital cost factor (in $/kW) by the capacity (in MW) of the unit. The capital costs so estimated were annualized assuming the equipment life as 15 years and a capital charge rate equal to 12%. The fixed O&M costs were estimated by multiplying the fixed O&M cost factor (in $/kW/yr) and the variable O&M costs were estimated by multiplying the variable O&M cost factor (in mills/kWh) with the electricity generation parameters. The annualized capital and the annual O&M costs were added together to estimate the annual cost of the retrofit controls. The existing and basecase projected NOx post-combustion controls non-ozone season variable O&M costs were estimated by multiplying the variable O&M cost factor (in mills/kWh) in the IPM documentation with the electricity generation (in kWh). The electricity generation values used are the IPM projections.

The emissions trading cost is the product of the difference between the Indiana budget and the IPM projected emissions (tons) and the projected allowance price ($/ton) for each pollutant. The fuel-switching cost accounts for switching to a different fuel (for example, switching to a lower sulfur coal or even to natural gas) to comply with the CAIR. This cost is the difference between the CAIR fuel cost and the basecase fuel cost. The fuel cost for each case was estimated by multiplying the projected heat input by the projected price for each fuel. The electricity generating cost is the difference between the CAIR electricity generating cost and the basecase electricity generating cost. The cost for each case was estimated by multiplying the projected electricity generation by the projected electricity generating price. The "additional capacity cost" is the difference between the projected "new capacity" costs for the CAIR and the basecase. The costs (including the capital and the fixed and variable O&M costs) for each case were estimated by using the cost factors in the IPM documentation, Exhibits 4-9 and 4-11.

The SUFG used a traditional regulation model to analyze the impact of the EGU costs on electricity prices. The model projects electric energy sales and peak demand as well as future electric rates given a set of exogenous factors. These factors describe the future of the Indiana economy and prices of fuels that compete with electricity in providing end-use services or are used to generate electricity. Combinations of econometric and end-use models are used to project electricity use for the major customer groups residential, commercial, and industrial. The modeling system predicts future electricity rates for these sectors by simulating the cost-of-service based rate structure traditionally used to determine rates under regulation. In this type of rate structure, ratepayers are typically allocated a portion of capital costs and fixed operating costs based on the customers' service requirements and are assigned fuel and other variable operating costs based upon the electric utility's out-of-pocket operating costs.

The SUFG performed the analysis for the five investor-owned utilities (Indiana Michigan Power Company, Indianapolis Power & Light Company, Northern Indiana Public Service Company, Cinergy, and Southern Indiana Gas & Electric Company) and three major not-for-profit entities (Hoosier Energy Rural Electric Cooperative, Indiana Municipal Power Agency, and Wabash Valley Power Association) that supply electric power to Indiana customers. The statewide electricity prices reported here were determined using energy-weighted averages of the five investor-owned utilities for the residential, commercial, and industrial sectors as well as for all customer groups combined. The rates for the units not regulated by the IURC were not analyzed.

Results

Tables 2 and 3 summarize the costs for the Scenario 1 (IDEM) and Scenario 2 (IUG). Under Scenario 1, a total of 17 SO2 scrubbers, 10 selective catalytic reduction systems (SCRs) and 2 selective non-catalytic reduction systems (SNCRs) are projected in the 2008-2022 timeframe. The cost of these controls, when fully implemented, is estimated at 1,853 million dollars in capital and 406 million dollars in annual (annualized capital and annual fixed and variable costs). The controls are projected at American Electric Power (AEP), Cinergy, Hoosier Energy, Indiana-Kentucky Electric Corporation (IKEC), Indianapolis Power & Light (IPL) and Southern Indiana Gas & Electric Company

(SIGECO). Please see Table A-1 in Appendix A for the utility-specific controls and costs. In addition, three-coal-fired units at the Cinergy Edwardsport facility and one coal-fired unit at the Whitewater facility are projected to retire early. During the time period 2018-2022, new capacities under CAIR are projected including approximately 300 MW in gas turbine and 1044 MW in the integrated gasification combined cycle (IGCC), whereas, in the basecase approximately 250 MW capacity in gas turbine and 648 MW in coal-fired generation are projected. The net cost of the additional capacity is estimated at 569 million dollars in capital and 102 million dollars in annual (annualized capital and annual fixed and variable costs). Please see Tables A-6-1 and A-6-2 in Appendix A for details. The Scenario 1 costs are estimated to increase the overall electricity rates by 5.16%, 5.97%, and 6.34% for the projection time intervals 2008-2012, 2013-2017, and 2018-2022. These estimates take into account the retrofit control costs, emissions trading costs and the NOx post-combustion control non-ozone season variable O&M costs.

Under Scenario 2, a total of 13 SO2 scrubbers and 6 SCRs are projected in the 2007-2022 time span. These controls, when fully implemented, are estimated to cost 2,296 million dollars in capital and 424 million dollars in annual (annualized capital and annual fixed and variable costs). The controls are projected at AEP, Cinergy, IKEC and Northern Indiana Public Service Commission (NIPSCO). Please see Table B-1 in Appendix B for the utility-specific controls and costs. As in Scenario 1, three-coal-fired units at the Cinergy Edwardsport facility and one coal-fired unit at the Whitewater facility are projected to retire early. In addition, in the year 2026, three-coal-fired units at the IPL Pritchard facility (units #1, 2 and 3) are projected to retire early. However, this projection year is beyond the time period considered in this impact analysis.

Under Scenario 2, additional capacities are projected in both the time spans 2014-2017 and 2018-2022. During the period 2014-2017, additional capacity in advanced combined cycle, equal to 892 MW is projected in the CAIR case and a capacity equal to 202 MW is projected in the basecase. The net cost of the additional capacity is estimated at 438 million dollars in capital and 67 million dollars in annual (annualized capital and annual fixed and variable costs). During the period 2018-2022, in the CAIR case, additional capacities, equal to1967 MW in advanced combined cycle, 21 MW in advanced combustion turbine and 729 MW in IGCC are projected. In the basecase, additional capacities equal to 202 MW in advanced combined cycle, 29 MW in advanced combustion turbine and 2028 MW in conventional pulverized coal are projected. The net cost of the additional capacity is estimated at negative (-) 675 million dollars in capital and negative (-) 101 million dollars in annual. The reason the net CAIR cost is negative, is the huge (2028 MW) capacity in conventional pulverized coal projected in the basecase. The capital cost of the conventional pulverized coal capacity (1,041 $/kW) is slightly less than that of IGCC (1,171$/kW) but significantly higher than that of the advanced combined cycle (535$/kW) and advanced combustion turbine (374$/kW). Please see Tables B-6-1 to B-6-4 in Appendix B for details.

The total EGU costs for Scenario 2 are estimated to increase the overall electricity rates by 6.44%, 8.55% and 7.63% for the projection time intervals 2007-2013, 2014-2017, and

2018-2022. These estimates take into account the retrofit control costs, emissions trading costs and the NOx post-combustion control non-ozone season variable O&M costs.

Non-electricity generating units (non-EGUs)

The non-EGU cost estimates are based on the ozone season NOx budget, projected emissions and the allowance prices. Table 4 shows the non-EGU sources in the emissions trading program, their emissions for the year 2004 and projected emissions for the 2010 to 2020 time period, proposed allowance allocations, and the total estimated costs. The emissions projections are based on the IDEM estimates. The allowance prices were taken from the USEPA CAIR Regulatory Impact Analysis. USEPA allowance prices are in 1999 dollars; they were adjusted to 2005 dollars, by using an adjustment factor equal to 1.20.

Table 4 shows that the year 2004 emissions and projected emissions for each source are less than its budget, therefore a need for additional controls to comply with the proposed allocations is not seen. The proposed allocations are for the years 2010 to 2014; thereafter the allocations may be revised. However, for all projection years the total of emissions is less than the budget, therefore a revenue ranging between 5 and 6 million dollars is expected.

Uncertainties in the analysis

The EGU cost estimates are sensitive to the assumptions made in the IPM analysis. In particular, the estimates are sensitive to the assumptions of fuel prices, electricity demand growth and the pollution control cost and effectiveness. The model assumes region wide emissions trading. USEPA's CAIR allows States the option not to participate in the emissions trading program. If one or more States do not participate in the trading program, it may affect the costs significantly. The analysis does not take into account the potential for advancement in the capabilities of SO2 and NOx controls. The non-EGU cost estimates are based on the projected emissions and allowance prices and they may change if the actual values are different from the projections.

References

1. Fiscal Impact Analysis. Office of Air Quality. Indiana Department of Environmental Management. September 29, 2005.
2. Regulatory Impact Analysis of the Final Clean Air Interstate Rule. EPA -452/R-05 002. March 2005. Available at: http://www.epa.gov/cair/technical.html
3. Fiscal Impact Statement, Proposed Rule 00-137. Bernadette Bartlett. Legislative Services Agency. February 2, 2001. Available at www.in.gov/legislative/pdf/00137.PDF
4. Comments IDEM CAIR Fiscal Impact Analysis. November 2005.
5. Comments on IDEM Fiscal Impact Analysis of Clean Air Interstate Rule Draft. Indiana Utility Group. November 7, 2005.
6. EPA Modeling Applications Using IPM. Available at http://www.epa.gov/airmarkets/epa-ipm

Table 2- Indiana CAIR EGU Cost Summary – **Scenario #1** (IDEM)

Model Year	2010	**2015**	2020
Time interval covered	2008-2012	**2013-2017**	2018-2022
Retrofit controls	3 SO2 scrubbers	12 SO2 scrubbers; 10 SCRs; 2 SNCRs	17 SO2 scrubbers; 10 SCRs; 2 SNCRs
Capital cost	413	1493	1853
Annualized capital cost	61	219	272
Fixed O&M cost	17	53	68
Variable O&M cost	17	57	66
Total annual cost	95	329	406
Existing &basecase projected SCRS/SNCRs non-ozone season variable O&M cost	35	37	36
Allowance purchase	196	203	200
New units			
Capital cost			569
Annualized capital cost			81
Annual O&M cost			20
Total annual cost			102
Fuel -switching	**6**	**7**	**-9**
Switch in electricity generation	**240**	**172**	**170**
Total costs			
Total capital cost	**413**	**1493**	**2422**
Total annual cost	**571**	**747**	**906**
Impact on electricity rates	**5.16%**	**5.97%**	**6.34%**

Note: (1) Retrofit control costs and SCR/SNCR non-ozone season variable O&M costs in each time interval are cumulative of the costs in the previous time interval.

(2) This Table is linked to other Tables. Due to rounding, the totals in this Table may not exactly match with the numbers in the supporting Tables

(3) The costs represent the incremental cost of CAIR

(4) Impact on electricity rates is estimated for IURC-regulated units only.

Table 3 -- Indiana CAIR EGU Cost Summary – Scenario #2 (IUG)

Year	2010	2015	2020
Time interval covered	2007-2013	2014-2017	2018-2022
Retrofit controls	11 SO2 scrubbers	11 SO2 scrubbers & 2 SCRs	13 SO2 scrubbers & 6 SCRs
Capital cost	1492	1689	2296
Annualized capital cost	179	203	275
Fixed O&M cost	51	52	63
Variable O&M cost	62	67	86
Total annual cost	292	322	424
Existing & basecase projected SCRS/SNCRs non-ozone season variable O&M cost	28	28	28
Allowance purchase	170	316	295
New units			
Capital cost		438	-675
Annualized capital cost		58	-84
Annual O&M cost		9	-17
Total annual cost		67	-101
Fuel -switching	**1**	**10**	**10**
Switch in electricity generation	**324**	**278**	**243**
Total costs			
Total capital cost	**1492**	**2127**	**1621**
Total annual cost	**815**	**1021**	**899**
Impact on electricity rates	**6.44%**	**8.55%**	**7.63%**
Note: (1)Retrofit control costs and SCR/SNCR non-ozone season variable O&M costs in each time interval are cumulative of the costs in the previous time interval.			
(2) This Table is linked to other Tables. Due to rounding, the totals in this Table may not exactly match with the numbers in the supporting Tables			
(3) The costs in this Table represent the incremental cost of CAIR			
(4) Impact on electricity rates is estimated for IURC-regulated units only.			

Table 4- Indiana CAIR Fiscal Impact Analysis
(Non-EGUs)

Plant Name	Allowancs (2010-2014)	2004 Emissions (tons)	Projected emissions 2010 (tons)	Projected emissions 2015 (tons)	Projected emissions 2020(tons)
AEP-ROCKPORT	4	1	1	1	1
AGC DIVISION - ALCOA POWER GENERATING	3,783	3,035	3,035	3,035	3,035
BP WHITING Business	1,484	730	353	353	353
C.C. PERRY K STEAM	640	528	515	508	501
Ispat Inland Inc.	1,267	177	169	161	156
NEW ENERGY CORP.	279	200	199	200	200
PORTSIDE ENERGY CORPORATION	89	30	30	30	30
PURDUE UNIVERSITY -WADE UTILITY PLANT	396	331	338	337	338
US Steel Corp. Gary Works	547	174	162	152	143
Total	8,489	5,207	4,803	4,778	4,757
Total budget (tons)			7,942	7,942	7,942
Surplus allowances			3,139	3,164	3,185
Allowance prices (1999$)			1,300	1,600	1,600
Allowance prices (2005$)			1,560	1,920	1,920
Revenue (million $)			5	6	6

Appendix A

CAIR Cost Spreadsheets

Scenario 1 (IDEM)

Table A-1 Indiana EGUs CAIR Retrofit Control Costs (Scenario #1-IDEM)

Retrofit Controls	SNCR	SCR	SO2 Scrubber	Total
Cinergy				
# of controls	2	7	6	
Total capital cost	5,188,427	211,444,344	760,747,608	977,380,379
Total annualized capital cost	761,787	31,045,155	111,696,189	143,503,131
Total fixed O&M cost	77,584	1,395,533	31,405,392	32,878,509
Total variable O&M cost	1,313,740	9,519,993	28,593,940	39,427,673
Total annualized cost	2,153,111	41,960,681	171,695,521	215,809,313
AEP				
# of controls		1	1	
Total capital cost		49,363,717	122,808,000	172,171,717
Total annualized capital cost		7,247,790	18,031,191	25,278,981
Total fixed O&M cost		325,801	5,076,000	5,401,801
Total variable O&M cost		2,474,793	4,465,938	6,940,731
Total annualized cost		10,048,384	27,573,129	37,621,513
Hoosier Energy				
# of controls		2	2	
Total capital cost		35,150,354	105,885,372	141,035,726
Total annualized capital cost		5,160,924	15,546,539	20,707,463
Total fixed O&M cost		231,992	4,417,740	4,649,732
Total variable O&M cost		1,405,240	2,170,408	3,575,648
Total annualized cost		6,798,156	22,134,687	28,932,843
IKEC				
# of controls			6	
Total capital cost			367,738,248	367,738,248
Total annualized capital cost			53,992,889	53,992,889
Total fixed O&M cost			16,883,148	16,883,148
Total variable O&M cost			11,138,115	11,138,115
Total annualized cost			82,014,152	82,014,152
IPL				
# of controls			1	
Total capital cost			101,057,184	101,057,184
Total annualized capital cost			14,837,644	14,837,644
Total fixed O&M cost			4,471,512	4,471,512
Total variable O&M cost			3,769,186	3,769,186
Total annualized cost			23,078,342	23,078,342
SIGECO				
# of controls			1	
Total capital cost			94,039,512	94,039,512
Total annualized capital cost			13,807,280	13,807,280
Total fixed O&M cost			4,085,304	4,085,304
Total variable O&M cost			1,205,782	1,205,782
Total annualized cost			19,098,366	19,098,366
Grand Total				
Total capital cost				1,853,422,766
Total annualized capital cost				272,127,388
Total fixed O&M cost				68,370,006
Total variable O&M cost				66,057,135
Total annualized cost				406,554,529

Table A-2 Indiana EGUs CAIR Post-combustion NOX Control Non-ozone season Variable O&M Costs (Scenario #1-IDEM)

Unit	Capacity (MW)-2004 NEEDS	Variable O&M cost (mills/kw-hr)-1999 $	Adjusted Variable O&M cost (mills/kw-hr)-1999$	Adjusted variable O&M cost (mills/kWhr)-2005$	2010 NOX post-combustion control	2010 CAIR non-ozone season electricity generation (kW-hr)	2010 non-ozone sesaon variable O&M cost (million $)-2005$	2015 NOX post combustion control	2015 CAIR non-ozone season electricity generation (kW-hr)	2015 non-ozone season variable O&M cost (million $)-2005 $	2020 NOX post combustion control	2020 CAIR non-ozone season electricity generation (kW-hr)	2020 non-ozone season variable O&M cost (million $)-2005 $
Baily 7	160	0.6	0.63	0.75	SCR (basecase)	664,029,430	0.50	SCR (basecase)	664,029,430	0.50	SCR (basecase)	664,029,430	0.50
Baily 8	320	0.6	0.58	0.70	SCR (exist)	1,328,058,861	0.93	SCR (exist)	1,328,058,861	0.93	SCR (exist)	1,328,058,861	0.93
Brown 1	250	0.6	0.60	0.72	SCR (exist)	1,037,716,405	0.74	SCR (exist)	1,037,716,405	0.74	SCR (exist)	1,037,716,405	0.74
Brown 2	250	0.6	0.60	0.72	SCR (exist)	1,037,517,642	0.74	SCR (exist)	1,037,517,642	0.74	SCR (exist)	1,038,393,450	0.75
Cliffty Creek 1	206	0.6	0.61	0.73	SCR (exist)	854,901,436	0.63	SCR (exist)	854,591,832	0.63	SCR (exist)	854,591,832	0.63
Cliffty Creek 2	208	0.6	0.61	0.73	SCR (exist)	863,201,450	0.63	SCR (exist)	862,888,840	0.63	SCR (exist)	862,888,840	0.63
Cliffty Creek 3	207	0.6	0.61	0.73	SCR (exist)	859,051,443	0.63	SCR (exist)	858,740,336	0.63	SCR (exist)	858,740,336	0.63
Cliffty Creek 4	205	0.6	0.61	0.73	SCR (exist)	850,751,429	0.62	SCR (exist)	850,443,328	0.62	SCR (exist)	850,443,328	0.62
Cliffty Creek 5	218	0.6	0.61	0.73	SCR (exist)	904,701,519	0.66	SCR (exist)	904,373,880	0.66	SCR (exist)	904,373,880	0.66
Cliffty Creek 6	203	0.6	0.61	0.73	SCR (basecase)	842,490,138	0.62	SCR (basecase)	842,490,138	0.62	SCR (basecase)	842,105,263	0.62
Culley 2	90	0.88	0.88	1.06				SNCR (basecase)	373,518,337	0.39	SNCR (basecase)	373,518,337	0.39
Culley 3	250	0.6	0.60	0.72	SCR (exist)	1,037,575,024	0.74	SCR (exist)	1,037,575,024	0.74	SCR (exist)	1,037,575,024	0.74
Gibson 1	630	0.6	0.54	0.65	SCR (exist)	2,613,554,218	1.69	SCR (exist)	2,613,554,218	1.69	SCR (exist)	2,613,554,218	1.69
Gibson 2	630	0.6	0.54	0.65	SCR (exist)	2,613,554,218	1.69	SCR (exist)	2,613,554,218	1.69	SCR (exist)	2,613,554,218	1.69
Gibson 3	630	0.6	0.54	0.65	SCR (exist)	2,613,554,218	1.69	SCR (exist)	2,613,554,218	1.69	SCR (exist)	2,613,554,218	1.69
Gibson 4	622	0.6	0.54	0.65	SCR (exist)	2,581,486,049	1.68	SCR (exist)	2,581,486,049	1.68	SCR (exist)	2,581,486,049	1.68
Gibson 5	619	0.6	0.54	0.65	SCR (exist)	2,569,014,450	1.67	SCR (exist)	2,569,014,450	1.67	SCR (exist)	2,569,014,450	1.67
Merom 1SG1	507	0.6	0.55	0.66	SCR (exist)	2,104,106,404	1.40	SCR (exist)	2,104,106,404	1.40	SCR (exist)	2,104,106,404	1.40
Merom 2SG1	493	0.6	0.56	0.67	SCR (exist)	2,046,004,846	1.36	SCR (exist)	2,046,004,846	1.36	SCR (exist)	2,046,004,846	1.36
Michigan City 12	469	0.6	0.56	0.67	SCR (exist)	1,946,422,208	1.30	SCR (exist)	1,946,422,208	1.30	SCR (exist)	1,946,422,208	1.30
Petersburg 2	407	0.6	0.57	0.68	SCR (exist)	1,689,117,952	1.15	SCR (exist)	1,689,127,365	1.15	SCR (exist)	1,689,127,365	1.15
Petersburg 3	510	0.6	0.55	0.66	SCR (exist)	2,116,485,434	1.40	SCR (exist)	2,116,485,434	1.40	SCR (exist)	2,116,485,434	1.40
Rockport MB1	1300	0.6	0.50	0.60	SCR (basecase)	5,395,517,893	3.23	SCR (basecase)	5,395,517,893	3.23	SCR (basecase)	5,395,517,893	3.23
Rockport MB2	1300	0.6	0.50	0.60	SCR (basecase)	5,395,517,893	3.23	SCR (basecase)	5,395,517,893	3.23	SCR (basecase)	5,395,517,893	3.23
Schahfer 14	431	0.6	0.56	0.68	SCR (exist)	1,788,736,886	1.21	SCR (exist)	1,788,736,886	1.21	SCR (exist)	1,788,736,886	1.21
Stateline 4	303	0.6	0.59	0.70	SCR (basecase)	1,257,500,262	0.88	SCR (basecase)	1,257,500,262	0.88	SCR (basecase)	1,257,500,262	0.88
Stout 50	106	0.88	0.88	1.06	SNCR (exist)	368,504,509	0.39	SNCR (exist)	439,918,704	0.46	SNCR (exist)	368,504,509	0.39
Stout 60	106	0.88	0.88	1.06	SNCR (exist)	368,504,571	0.39	SNCR (exist)	439,918,777	0.46	SNCR (exist)	368,504,571	0.39
Stout 70	422	0.6	0.56	0.68	SCR (exist)	1,751,291,092	1.19	SCR (exist)	1,751,306,943	1.19	SCR (exist)	1,750,614,771	1.19
Tanners Creek U1	140	0.6	0.64	0.76	SCR (basecase)	581,027,941	0.44	SCR (basecase)	581,027,941	0.44	SCR (basecase)	581,027,941	0.44
Tanners Creek U2	140	0.6	0.64	0.76	SCR (basecase)	581,027,941	0.44	SCR (basecase)	581,027,941	0.44	SCR (basecase)	581,027,941	0.44
Tanners Creek U3	200	0.6	0.61	0.74	SCR (basecase)	830,039,916	0.61	SCR (basecase)	830,039,916	0.61	SCR (basecase)	830,039,916	0.61
Wabash River 2	85	0.88	0.88	1.06				SNCR (basecase)	295,500,137	0.31	SNCR (basecase)	295,500,137	0.31
Wabsh River 4	85	0.88	0.88	1.06				SNCR (basecase)	295,500,137	0.31	SNCR (basecase)	295,500,137	0.31
Wabsh River 5	95	0.88	0.88	1.06				SNCR (basecase)	394,285,040	0.42	SNCR (basecase)	295,500,137	0.31
Warrick 4	323	0.6	0.58	0.70	SCR (exist)	560,247,150	0.39	SCR (exist)	560,252,221	0.39	SCR (exist)	560,030,792	0.39
Whitewater Valley 1	35				retire			retire		0.00	retire		0.00
Whitewater Valley 2	63	0.88	0.88	1.06	SNCR (exist)	168,064,447	0.18	SNCR (exist)	117,140,453	0.12	SNCR (exist)		0.00
Total							35.08			36.61			36.23

1. Variable O&M cost factor taken from USEPA IPM documentation v 2.1.9. Exhibit 5-4.

Table A-3-1 Indiana EGUs Emissions Trading Costs –Year 2010-(Scenario #1-IDEM)

Utility	Total Summer NOX (tons)	Total annual NOX (tons)	Total SO2 (tons)	Allocations summer NOX	Allocations annual NOX	Allocations SO2	Allowance price (Summer NOX)	Allowance price (annual NOX)	Allowance price (SO2)	Allowance trading cost (million $)- summer NOX	Allowance trading cost (million $)- annual NOX	Allowance trading cost (million $)- SO2	Total allowance trading cost (million $)- 1999$	Total allowance trading cost (million $)- 2005$- (2005/1999 adjustment factor=1.20)
AEP/I&M	5948.2	13437.5	98253.9	8,183	19,058	41,653	1300	1300	700	(3)	(7)	40	29.409	35.29
Cinergy	15455.975	37158.0716	110173	12,247	29,237	71,956	1300	1300	700	4	10	27	41.221	49.47
DPL Energy LLC	0.0000	0.0000	0.0000	37	46	-	1300	1300	700	(0)	(0)	-	(0.108)	-0.13
Hoosier Energy	2620.35732	6323.23705	22061.8083	3,211	7,809	18,534	1300	1300	700	(1)	(2)	2	(0.230)	-0.28
IKEC	1502.3	3701.1	48780.2	2,708	6,572	25,288	1300	1300	700	(2)	(4)	16	11.145	13.37
IMPA	0	0	0	17	19	0	1300	1300	700	0	0	0	0	-0.06
IPL/AES	13015.2725	30183.3432	51000.7394	5913	14502	35995	1300	1300	700	9	20	11	40.123	48.15
Mirant	20.704639	57.4847461	0	76	82	-	1300	1300	700	(0)	(0)	-	(0.104)	-0.12
NIPSCO	9589.67169	21665.1892	68893.7	6753	15513	25353	1300	1300	700	4	8	30	42.164	50.60
RPL	339.9	767.9	3910.7	257	587	4,474	1300	1300	700	0	0	(0)	(0.051)	-0.06
SIGECO	2408.73928	5665.00235	16607.8523	3,045	7,168	15,498	1300	1300	700	(1)	(2)	1	(2.004)	-2.40
SL-Dominion	933.6	2261.1	9246.3	1,017	2,476	4,743	1300	1300	700	(0)	(0)	3	2.765	3.32
Whiting Clean Energy	19.0831987	43.9761712	0	190	417	-	1300	1300	700	(0)	(0)	-	(0.707)	-0.85
Totals	51,854	121,264	428,928	43,654	103,486	243,494						Total Cost	163.575	196.290

Note: (1)Allowance prices are from USEPA CAIR Regulatory Impact Analysis. March 2005. Table 7-3
(2) Numbers in parenthesis represent negative cost, i.e., revenue
(3)Totals of allocations do not match with the budgets in the Rule due to rounding.

Table A-3-2 Indiana EGUs Emissions Trading Costs –Year 2015 –(Scenario #1 –IDEM)

Utility	Total Summer NOX (tons)	Total annual NOX (tons)	Toal SO2 (tons)	Allocations summer NOX	Allocations annual NOX	Allocations SO2	Allowance price (Summer NOX)	Allowance price (annual NOX)	Allowance price (SO2)	Allowance trading cost (million $)- summer NOX	Allowance trading cost (million $)- annual NOX	Allowance trading cost (million $)- SO2	Total allowance trading cost (million $)- 1999$	Total allowance trading cost (million $)- 2005$ (2005/1999 adjustment factor =1.20
AEP-I&M	3,514.90	7,940.40	84,371.20	7,140	16,218	29,157	1,600	1,600	1,000	(5.80)	(13.24)	55.21	36.17	43.40
Cinergy	7,587.09	17,494.93	80,716.20	10,687	24,881	50,369	1,600	1,600	1,000	(4.96)	(11.82)	30.35	13.57	16.28
DPL Energy LLC	13.69	32.05	-	32	39	-	1,600	1,600	1,000	(0.03)	(0.01)	-	(0.04)	(0.05)
Hoosier Energy	1,334.13	3,050.28	22,347.09	2,802	6,645	12,973	1,600	1,600	1,000	(2.35)	(5.75)	9.37	1.27	1.53
IKEC	1,706.30	3,904.40	12,579.90	2,363	5,593	17,702	1,600	1,600	1,000	(1.05)	(2.70)	(5.12)	(8.87)	(10.65)
IMPA	0.00	0.00	0.00	15	16	-	1,600	1,600	1,000	(0.02)	(0.03)	-	(0.05)	(0.06)
IPL/AES	9,705.22	22,690.15	52,599.28	5,160	12,341	25,197	1,600	1,600	1,000	7.27	16.56	27.40	51.23	61.48
Mirant	79.19	183.36	-	66	70	-	1,600	1,600	1,000	0.02	0.18	-	0.20	0.24
NIPSCO	9,592.11	22,169.33	70,798.60	5,893	13,202	17,747	1,600	1,600	1,000	5.92	14.35	53.05	73.32	87.98
RPL	-	298.300	1,519.200	224	500	3,131	1,600	1,600	1,000	(0.36)	(0.32)	(1.61)	(2.29)	(2.75)
SIGECO	1,401.981	3,186.458	16,771.833	2,657	6,100	10,848	1,600	1,600	1,000	(2.01)	(4.66)	5.92	(0.75)	(0.90)
SL-Dominion	933.600	2,261.100	9,246.300	887	2,107	3,320	1,600	1,600	1,000	0.07	0.25	5.93	6.25	7.50
Whiting Clean Energy	57.292	131.992	-	166	355	-	1,600	1,600	1,000	(0.17)	(0.36)	-	(0.53)	(0.64)
	35,925	83,343	350,950	38,092	88,067	170,444								
												Total Cost	**169.48**	**203.38**

Note: (1)Allowance prices are from USEPA CAIR Regulatory Impact Analysis. March 2005. Table 7-3

(2) Numbers in parenthesis represent negative cost, i.e., revenue

(3) Alowances for 2015 and beyond are not allocated yet. For these calculations, the allowances were estimated by multiplying the 2010 allocations by the ratio of Phase 2 to Phase I budget (0.8726 for ozone season and 0.851 for annual). Totals of allocations do not match with the budgets in the Rule due to rounding.

Table A-3-3 Indiana EGUs Emissions Trading Costs –Year 2020 –(Scenario #1-IDEM)

Utility	Total summer NOX (tons)	Total annual NOX (tons)	Total SO2 (tons)	Allocations summer NOX	Allocations annual NOX	Allocations SO2	Allowance price (Summer NOX)	Allowance price (annual NOX)	Allowance price (SO2)	Allowance trading cost (million $)- summer NOX	Allowance trading cost (million $)- annual NOX	Allowance trading cost (million $)- SO2	Total allowance trading cost (million $)- 1999$	Total allowance trading cost (million $)-2005$ -(2005/1999 adjustment factor =1.20)
AEP-I&M	3,514 90	7,940.40	84,371.20	7,140	16,218	29,157	1,600.00	1,600.00	1,400.00	(5.80)	(13.24)	77.30	58.25	69.91
Cinergy	11,038 71	26,337.18	79,966.60	10,687	24,881	50,369	1,600.00	1,600.00	1,400.00	0.56	2.33	41 44	44.33	53.20
DPL Energy LLC	13 69	32.05	-	32	39	-	1,600.00	1,600.00	1,400.00	(0.03)	(0.01)	-	(0.04)	(0.05)
Hoosier Energy	1,360 11	3,076.12	14,699.77	2,802	6,645	12,973	1,600.00	1,600.00	1,400.00	(2.31)	(5.71)	2.42	(5.60)	(6.72)
IKEC	1,745 70	3,943.60	6,231.50	2,363	5,593	17,702	1,600.00	1,600.00	1,400.00	(0.99)	(2.64)	(16.06)	(19.69)	(23.62)
IMPA	-	-	-	15	16	-	1,600.00	1,600.00	1,400.00	(0.02)	(0.03)	-	(0.05)	(0.06)
IPL/AES	4,567 10	11,042.98	39,680.25	5,160	12,341	25,197	1,600.00	1,600.00	1,400.00	(0.95)	(2.08)	20.28	17.25	20.70
Mirant	79 19	183.36	-	66	70	-	1,600.00	1,600.00	1,400.00	0.02	0.18	-	0.20	0.24
NIPSCO	6,230.82	14,675.83	67,077.30	5,893	13,202	17,747	1,600.00	1,600.00	1,400.00	0.54	2.36	69.06	71.96	86.35
RPL	-	-	-	224	500	3,131	1,600.00	1,600.00	1,400.00	(0.36)	(0.80)	(4.38)	(5.54)	(6.65)
SIGECO	1,670.55	3,774.35	12,376.08	2,657	6,100	10,848	1,600.00	1,600.00	1,400.00	(1.58)	(3.72)	2.14	(3.16)	(3.79)
SL-Dominion	1,054 40	2,381.90	9,558.40	887	2,107	3,320	1,600.00	1,600.00	1,400.00	0.27	0.44	8.73	9.44	11.33
Whiting Clean Energy	57 29	131.99	-	166	355	-	1,600.00	1,600.00	1,400.00	(0.17)	(0.36)	-	(0.53)	(0.64)
	31,332	73,520	313,961	38,092	88,067	170,444				(10.82)	(23.27)	200.92	166.83	200.20

Note: (1)Allowance prices are from USEPA CAIR Regulatory Impact Analysis. March 2005. Table 7-3

(2) Numbers in parenthesis represent negative cost, i.e., revenue

(3) Alowances for 2015 and beyond are not allocated yet. For these calculations, the allowances were estimated by multiplying the 2010 allocations by the ratio of Phase 2 to Phase I budget (0.8726 for ozone season and 0.851 for annual). Totals of allocations do not match with the budgets in the Rule due to rounding.

Table A-4 Indiana EGUs CAIR Fuel-switching Costs

Year	Calculations	Year	Calculations	Year	Calculations
2010		2015		2020	
Basecase		Basecase		Basecase	
Bituminous coal		**Bituminous coal**		**Bituminous coal**	
Heat input (trillionBTU)	1268.3795	Heat input (trillionBTU)	1290.541	Heat input (trillionBTU)	1341.88889
Heat content (mmBtu/ton)	23.8	Heat content (mmBtu/ton)	23.8	Heat content (mmBtu/ton)	23.8
coal use (tons)	53,293,256	coal use (tons)	54,224,412	coal use (tons)	56,381,886
Price ($/ton)	12.24	Price ($/ton)	11.85	Price ($/ton)	10.84
Total cost (million $)	652	Total cost (million $)	643	Total cost (million $)	611
Subbituminous Coal		**Subbituminous Coal**		**Subbituminous Coal**	
Heat input (trillionBTU)	189.5067	Heat input (trillionBTU)	189.51	Heat input (trillionBTU)	193.5834
Heat content (mmBtu/ton)	17.1	Heat content (mmBtu/ton)	17.1	Heat content (mmBtu/ton)	17.1
coal use (tons)	11,082,263	coal use (tons)	11,082,456	coal use (tons)	11,320,667
Price ($/ton)	6.82	Price ($/ton)	6.8	Price ($/ton)	6.47
Total cost (million $)	76	Total cost (million $)	75	Total cost (million $)	73
Total basecase coal cost (million $)	**727.89**	**Total basecase coal cost (million $)**	**717.92**	**Total basecase coal cost (million $)**	**684.42**
CAIR		CAIR		CAIR	
Bituminous coal		**Bituminous coal**		**Bituminous coal**	
Heat input (trillionBTU)	1251.6302	Heat input (trillionBTU)	1275.9	Heat input (trillionBTU)	1327.5
Heat content (mmBtu/ton)	23.8	Heat content (mmBtu/ton)	23.8	Heat content (mmBtu/ton)	23.8
coal use (tons)	52,589,504	coal use (tons)	53,609,244	coal use (tons)	55,777,311
Price ($/ton)	12.24	Price ($/ton)	11.85	Price ($/ton)	10.84
Total cost (million $)	644	Total cost (million $)	635	Total cost (million $)	605
Subbituminous Coal		**Subbituminous Coal**		**Subbituminous Coal**	
Heat input (trillionBTU)	185.6967	Heat input (trillionBTU)	189.51	Heat input (trillionBTU)	186.4148
Heat content (mmBtu/ton)	17.1	Heat content (mmBtu/ton)	17.1	Heat content (mmBtu/ton)	17.1
coal use (tons)	10,859,456	coal use (tons)	11,082,456	coal use (tons)	10,901,450
Price ($/ton)	6.82	Price ($/ton)	6.8	Price ($/ton)	6.47
Total cost (million $)	74	Total cost (million $)	75	Total cost (million $)	71
Total CAIR coal cost (million $)	**717.76**	**Total CAIR coal cost (million $)**	**710.63**	**Total CAIR coal cost (million $)**	**675.16**
Natural gas		**Natural gas**		**Natural gas**	
Base case		**Base case**		**Base case**	
Heat input (trillion Btu)	20.7379	Heat input (trillion Btu)	66.875	Heat input (trillion Btu)	72.60306
Price ($/mmBtu)	4.08	Price ($/mmBtu)	4.08	Price ($/mmBtu)	4.08
Total basecase natural gas cost cost (million $)	**85**	**Total basecase natural gas cost (million $)**	**273**	**Total basecase natural gas cost (million $)**	**296**
CAIR		**CAIR**		**CAIR**	
Heat input (trillion Btu)	24.4496	Heat input (trillion Btu)	70.014	Heat input (trillion Btu)	73.118598
Price ($/mmBtu)	4.08	Price ($/mmBtu)	4.08	Price ($/mmBtu)	4.08
Total CAIR natural gas cost (million $)	**100**	**Total CAIR natural gas cost (million $)**	**286**	**Total CAIR natural gas cost (million $)**	**298**
Incremental CAIR Fuel cost -1999$ - million $	**5.01**	**Incremental CAIR Fuel cost -1999$ - million $**	**5.52**	**Incremental CAIR Fuel cost -1999$ - million $**	**(7.16)**
2005/1999 cost adjustment factor	1.20	2005/1999 cost adjustment factor	1.20	2005/1999 cost adjustment factor	1.20
Incremental CAIR Fuel cost -2005 - million $	6.01	**Incremental CAIR Fuel cost -2005 - million $**	6.62	**Incremental CAIR Fuel cost -2005 - million $**	-8.60

Table A-5 Indiana EGUs CAIR Switch-in Electricity Generating Costs (Scenario #1-IDEM)

	Scenario #1-IDEM using USEPA IPM- Electricity Generating Costs-Using IUG Estimated Electricity prices-wholesale prices									
Year	Basecase electricity generation (kWhr)	CAIR electricity generation (kWhr)	Base case wholesale electricity price (mills/kWhr)	CAIR wholesale electricity price (mills/kWhr)	Basecase electricity prices (million$)-1999$	CAIR electricity prices (million$)-1999$	Incremental CAIR cost (million $) - 1999 $	2005/1999 price adjustment factor	Incremental CAIR cost (million $) - 2005 $	Difference-% of total price
2010	141,320,611,310	140,013,518,498	29.40	31.10	4154.83	4354.42	200	1.20	240	6%
2015	149,573,036,727	148,923,067,216	31.50	32.60	4711.55	4854.89	143	1.20	172	4%
2020	156,382,446,944	156,420,376,547	32.40	33.30	5066.79	5208.80	142	1.20	170	3%

Table A-6-1 Indiana EGUs CAIR Additional Electricity Generating Capacity Costs (Scenario #1 –IDEM)

IPM projected unit (type)	turbine	IGCC	turbine
Construction cost			
Capacity (MW)	281.45	1043.91	18.27
Unit type (based on capacity)-Exhibit 4-9-U.S.EPA. IPM v.2.1.9	combustion turbine	IGCC	combustion turbine
Vintage-Exhibit 4-9-U.S.EPA. IPM v.2.1.9	2020-2030	2020-2030	2020-2030
Heat rate (Btu/kWh)	10450	7200	10450
Capital cost ($/kW)	374	1171	374
Total capital cost (million$)	105	1222	7
Capital charge rate -Exhibit 7-1, U.S. EPA IPM v. 2.1.9-%	13.400	13.400	13.400
Equipment life (years)	30	30	30
Capital recovery factor	0.137	0.137	0.137
Annualized capital cost (million$/yr)	14.44	167.66	0.94
Fixed O&M cost ($/kW-yr)	9.74	32.12	9.74
Kw--yr	281,450	1,043,908	18,270
Fixed O&M cost (million $/yr)	2.74	33.53	0.18
Variable O&M cost ($/Mwh)	3.90	1.95	3.90
Capacity factor -assumed	60	70	60
Electricity generation (Mwh)	1,479,301	6,401,244	96,027
Variable O&M cost (million$/yr)	5.77	12.48	0.37
Regional adjustment factor -Exhibit 4-11, USEPA IPM v. 2.1.9	1.004	1.004	1.004
Adjusted capital cost (million $)	105.683	1227.306	6.860
Adjusted annualized capital cost (million $)	14.495	168.330	0.941
Fixed O&M cost (million $/yr)	9.740	32.120	9.740
Variable O&M cost	5.769	12.482	0.375
Total annual cost (million $/yr)	30.00	212.93	11.06
Emissions monitoring			
IGCC			
NOX & SO2 CEMs (memo, USEPA CAIR Docket)			
Capital cost (million$)		0.163	
Annualized capital cost (million$)		0.021	
Annual O&M cost (million $)		0.039	
Combined Cycle			
NOX & SO2 CEMs (memo, USEPA CAIR Docket)			
Capital cost (million $)	0.163		
Annualized capital cost	0.021		
Annual O&M cost	0.039		
Grand Total	CAIR cost	Basecase cost	Difference
Capital cost (million $)	1340.18	771.12	569.05
Annualized capital cost (million$)	183.81	102.59	81.21
Annual O&M cost (million $)	70.30	49.90	20.41
Total annual cost (million$)	254.11	152.49	101.62

Table A-6-2 Indiana EGUs Additional Electricity Generating Capacity Costs (Basecase) (Scenario #1 –IDEM)

IPM projected unit (type)	turbine	Coal steam
Construction cost		
Capacity (MW)	249.95	647.69
Unit type (based on capacity)-Exhibit 4-9-U.S.EPA. IPM v.2.1.9	combustion turbine	conventional pulverized coal
Vintage-Exhibit 4-9-U.S.EPA. IPM v.2.1.9	2020-2030	2020-2030
Heat rate (Btu/kWh)	10450	8600
Capital cost ($/kW)	374	1041
Total capital cost (million$)	93	674
Capital charge rate -Exhibit 7-1, U.S. EPA IPM v. 2.1.9 -(%)	13.4	12.9
Equipment life -years	30	30
Capital recovery factor	0.137	0.132
Annualized capital cost (million$/yr)	12.82	89.32
Fixed O&M cost ($/kW-yr)	9.74	23.36
Kw--yr	249,948	647,691
Fixed O&M cost (million $/yr)	2.43	15.13
Variable O&M cost ($/Mwh)	3.90	2.92
Capacity factor -assumed	60	70
Electricity generation (Mwh)	1,313,727	3,971,641
Variable O&M cost (million$/yr)	5.12	11.60
Regional adjustment factor -Exhibit 4-11, USEPA IPM v. 2.1.9	1.004	1.004
Adjusted capital cost (million $)	93.854	676.943
Adjusted annualized capital cost (million $)	12.872	89.680
Fixed O&M cost (million $/yr)	9.740	23.360
Variable O&M cost	5.124	11.597
Total annual cost (million $/yr)	27.74	124.64
Emissions monitoring		
Pulverized coal		
NOX & SO2 CEMs (memo, USEPA CAIR Docket)		
Capital cost (million$)		0.163
Annualized capital cost (million$)		0.021
Annual O&M cost (million $)		0.039
Combustion turbine		
NOX & SO2 CEMs (memo, USEPA CAIR Docket)		
Capital cost (million $)	0.163	
Annualized capital cost	0.021	
Annual O&M cost	0.039	
Grand Total		
Capital cost (million $)	771.124	
Annualized capital cost (million$)	102.595	
Annual O&M cost (million $)	49.899	
Total annual cost (million$)	152.494	

Appendix B

CAIR Cost Spreadsheets

Scenario 2 (IUG)

Table B-1 Indiana EGUs CAIR Retrofit Control Costs (Scenario #2-IUG)

Retrofit control	SNCR	SCR	SO2 Scrubber	Total
Cinergy				
# of controls		3	6	
Total capital cost		273	1,077	1,351
Total annualized capital cost		33	129	162
Total fixed O&M cost		1	35	36
Total variable O&M cost		8	46	54
Total annualized cost		42	211	253
AEP				
# of controls		1	1	
Total capital cost		101	175	276
Total annualized capital cost		12	21	33
Total fixed O&M cost		1	5	6
Total variable O&M cost		4	4	8
Total annualized cost		17	30	47
IKEC				
# of controls			6	
Total capital cost			543	543
Total annualized capital cost			65	65
Total fixed O&M cost			20	20
Total variable O&M cost			18	18
Total annualized cost			103	103
NIPSCO				
# of controls		2		
Total capital cost		127		127
Total annualized capital cost		15		15
Total fixed O&M cost		1		1
Total variable O&M cost		6		6
Total annualized cost		22		22
Grand Total				
Total capital cost				2,296
Total annualized capital cost				275
Total fixed O&M cost				63
Total variable O&M cost				86
Total annualized cost				424

Table B-2 Indiana EGUs CAIR Post-combustion NOX Control Non-ozone season Variable O&M Costs (Scenario #2-IUG)

Notes: 2010 was not modeled in the IEA analyses. Since 2010 is mapped to 2012, the results shown here are for the 2012 model run year. Since the parsed results for 2020 are not available at this time, the generation for 2020 is assumed to be the same as in 2015. The Vairable O&M cost factor is from the EPA IPM Documentation v2.1.9 Exhibit 5-4. 1999$ were converted to 2005$ using an inflation rate of 1.20.

Unit	Capacity (MW)	NOX post-combustion control 2010	non-ozone season electricity generation (kW-hr) Policy Case 2010	non-ozone season electricity generation (kW-hr) Policy Case 2015	non-ozone season electricity generation (kW-hr) Policy Case 2020	Variable O&M cost (mills/kw-hr)	Adjusted Variable O&M cost (mills/kw-hr)	non-ozone sesaon variable O&M cost (million $)-1999$ Policy Case 2010	non-ozone sesaon variable O&M cost (million $)-1999$ Policy Case 2015	non-ozone season variable O&M cost (million $)-1999$ Policy Case 2020	Policy Case 2010 non-ozone season variable O&M cost (million $)-2005 $	Policy Case 2015 non-ozone season variable O&M cost (million $)-2005 $	Policy Case 2020 non-ozone season variable O&M cost (million $)-2005 $
Bailly 7	160	SCR	664,029,431	664,029,431	664,029,431	0.60	0.63	0.42	0.42	0.42	0.50	0.50	0.50
Bailly 8	320	SCR	1,328,058,861	1,328,058,861	1,328,058,861	0.60	0.58	0.77	0.77	0.77	0.93	0.93	0.93
Brown 1	250	SCR (exist)	1,037,521,279	1,037,521,279	1,037,521,279	0.60	0.60	0.62	0.62	0.62	0.74	0.74	0.74
Brown 2	250	SCR (exist)	1,037,514,100	1,037,514,100	1,037,514,100	0.60	0.60	0.62	0.62	0.62	0.74	0.74	0.74
Cliffty Creek 1	199.3	SCR (exist)	825,512,893	825,512,893	825,512,893	0.60	0.61	0.51	0.51	0.51	0.61	0.61	0.61
Cliffty Creek 2	199.3	SCR (exist)	826,588,649	826,588,649	826,588,649	0.60	0.61	0.51	0.51	0.51	0.61	0.61	0.61
Cliffty Creek 3	199.3	SCR (exist)	826,588,649	826,588,649	826,588,649	0.60	0.61	0.51	0.51	0.51	0.61	0.61	0.61
Cliffty Creek 4	199.3	SCR (exist)	826,588,649	826,588,649	826,588,649	0.60	0.61	0.51	0.51	0.51	0.61	0.61	0.61
Cliffty Creek 5	199.3	SCR (exist)	826,588,649	826,588,649	826,588,649	0.60	0.61	0.51	0.51	0.51	0.61	0.61	0.61
Cliffty Creek 6	199.3	SCR	825,486,917	825,486,917	825,486,917	0.60	0.61	0.51	0.51	0.51	0.61	0.61	0.61
Culley 3	270	SCR(exist)	1,120,536,585	1,120,536,585	1,120,536,585	0.60	0.59	0.66	0.66	0.66	0.80	0.80	0.80
Gibson 1	630	SCR (exist)	2,594,253,068	2,594,253,068	2,594,253,068	0.60	0.54	1.40	1.40	1.40	1.68	1.68	1.68
Gibson 2	630	SCR (exist)	2,594,253,068	2,594,253,068	2,594,253,068	0.60	0.54	1.40	1.40	1.40	1.68	1.68	1.68
Gibson 3	630	SCR (exist)	2,594,253,068	2,594,253,068	2,594,253,068	0.60	0.54	1.40	1.40	1.40	1.68	1.68	1.68
Gibson 4	622	SCR (exist)	2,581,388,108	2,581,388,108	2,581,388,108	0.60	0.54	1.40	1.40	1.40	1.68	1.68	1.68
Gibson 5	620	SCR (exist)	2,573,086,944	2,573,086,944	2,573,086,944	0.60	0.54	1.39	1.39	1.39	1.67	1.67	1.67
Merom 1SG1	507	SCR	2,104,106,405	2,104,106,405	2,104,106,405	0.60	0.55	1.16	1.16	1.16	1.40	1.40	1.40
Merom 2SG1	493	SCR	2,046,004,846	2,046,004,846	2,046,004,846	0.60	0.56	1.14	1.14	1.14	1.36	1.36	1.36
Michigan City 12	469	SCR (exist)	1,946,422,208	1,946,422,208	1,946,422,208	0.60	0.56	1.09	1.09	1.09	1.30	1.30	1.30
Petersburg 2	407	SCR	1,689,127,365	1,689,127,365	1,689,127,365	0.60	0.57	0.96	0.96	0.96	1.15	1.15	1.15
Petersburg 3	510	SCR	2,116,531,523	2,116,531,523	2,116,531,523	0.60	0.55	1.17	1.17	1.17	1.40	1.40	1.40
Schahfer 14	431	SCR	1,788,736,886	1,788,736,886	1,788,736,886	0.60	0.56	1.01	1.01	1.01	1.21	1.21	1.21
Stateline 4	303	SCR	1,257,500,262	1,257,500,262	1,257,500,262	0.60	0.59	0.74	0.74	0.74	0.88	0.88	0.88
Stout 50	109	SNCR	452,372,177	452,032,198	452,032,198	0.88	0.88	0.40	0.40	0.40	0.48	0.48	0.48
Stout 60	109	SNCR	452,372,177	452,032,198	452,032,198	0.88	0.88	0.40	0.40	0.40	0.48	0.48	0.48
Stout 70	435	SCR	1,804,238,271	1,804,238,271	1,804,238,271	0.60	0.56	1.02	1.02	1.02	1.22	1.22	1.22
Wabash River 2	85	SNCR	327,834,527	327,834,527	327,834,527	0.88	0.88	0.29	0.29	0.29	0.35	0.35	0.35
Wabash River 3	85	SNCR	327,834,527	327,834,527	327,834,527	0.88	0.88	0.29	0.29	0.29	0.35	0.35	0.35
Wabash River 4	85	SNCR	342,534,039	342,534,039	342,534,039	0.88	0.88	0.30	0.30	0.30	0.36	0.36	0.36
Warrick 4	323	SCR	622,151,128	622,151,128	622,151,128	0.60	0.58	0.36	0.36	0.36	0.43	0.43	0.43
Total											28.13	28.12	28.12

Table B-3-1 Indiana EGUs Emissions Trading Costs --Ozone Season NOx-(Scenario #2-IUG)

	Ozone Season NOx Emissions (Thousand Tons)				Ozone Season NOx Allocation (Thousand Tons)				Ozone Season NOx Allowance Price (2005$/Ton)				Ozone Season NOx Trading Cost (Thousand 2005$)			
Utility	2009	2012	2015	2020	2009	2012	2015	2020	2009	2012	2015	2020	2009	2012	2015	2020
AEP/I&M	14.22	14.71	14.72	12.30	8.18	8.18	6.97	6.97	3,658	74	86	-	22,089	481	667	-
Cinergy	15.63	16.50	11.71	10.60	12.39	12.39	10.55	10.55	3,658	74	86	-	11,880	303	100	-
DPL Energy LLC	0.00	0.01	0.01	0.01	0.04	0.04	0.03	0.03	3,658	74	86	-	(125)	(2)	(2)	-
Hoosier Energy	3.52	3.61	3.61	3.56	3.21	3.21	2.74	2.74	3,658	74	86	-	1,144	30	76	-
IKEC	1.44	1.75	1.75	1.75	2.71	2.71	2.31	2.31	3,658	74	86	-	(4,644)	(70)	(48)	-
IMPA	0.00	0.00	0.00	0.00	0.02	0.02	0.01	0.01	3,658	74	86	-	(62)	(1)	(1)	-
IPL/AES	7.20	7.22	7.08	6.65	5.91	5.91	5.04	5.04	3,658	74	86	-	4,717	96	176	-
Mirant	0.03	0.08	0.08	0.08	0.08	0.08	0.06	0.06	3,658	74	86	-	(177)	0	1	-
NIPSCO	11.27	11.27	11.27	8.44	6.75	6.75	5.75	5.75	3,658	74	86	-	16,529	333	475	-
RPL	0.34	-	-	-	0.26	0.26	0.22	0.22	3,658	74	86	-	303	(19)	(19)	-
SIGECO	1.64	1.77	1.77	1.64	3.05	3.05	2.59	2.59	3,658	74	86	-	(5,145)	(94)	(71)	-
SL-Dominion	3.22	1.21	1.21	1.21	1.02	1.02	0.87	0.87	3,658	74	86	-	8,063	14	30	-
Whiting Clean Energy	0.02	0.06	0.06	0.06	0.19	0.19	0.16	0.16	3,658	74	86	-	(609)	(10)	(9)	-
New units	0.13	0.16	0.30	0.63	2.16	2.16	1.96	1.96	3,658	74	86	-	(7,414)	(147)	(143)	-
Totals (existing and new)	58.68	58.37	53.59	46.95	45.95	45.95	39.27	39.27					46,550.83	914.96	1,232.12	-

Table B-3-2 Indiana EGUs Emissions Trading Costs –Annual NOx-(Scenario #2-IUG)

Utility	2009	2012	2015	2020	2009	2012	2015	2020	2009	2012	2015	2020	2009	2012	2015	2020
AEP/I&M	9.85	9.85	9.85	9.85	7.40	7.40	6.16	6.16	1,753	2,046	2,391	2,852	4,296	5,013	8,806	10,505
AEP/I&M	32.94	33.43	33.43	28.01	19.00	19.00	15.83	15.83	1,753	2,046	2,391	2,852	24,440.69	29,525.90	42,081.21	34,740.94
Cinergy	36.82	37.75	27.72	24.28	29.47	29.47	24.56	24.56	1,753	2,046	2,391	2,852	12,886.56	16,935.05	7,561.50	(806.09)
DPL Energy LLC	0.02	0.03	0.03	0.03	0.05	0.05	0.04	0.04	1,753	2,046	2,391	2,852	(44)	(29)	(15)	(18)
Hoosier Energy	8.13	8.22	8.22	8.12	7.78	7.78	6.49	6.49	1,753	2,046	2,391	2,852	606	890	4,142	4,645
IKEC	3.58	3.96	3.96	3.96	6.55	6.55	5.46	5.46	1,753	2,046	2,391	2,852	(5,201)	(5,291)	(3,574)	(4,264)
IMPA	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.02	1,753	2,046	2,391	2,852	(27)	(27)	(24)	(28)
IPL/AES	16.94	16.65	16.37	15.26	14.46	14.46	12.05	12.05	1,753	2,046	2,391	2,852	4,363	4,486	10,328	9,159
Mirant	0.08	0.23	0.18	0.18	0.08	0.23	0.18	0.18	1,753	2,046	2,391	2,852	5	305	276	329
NIPSCO	25.97	25.97	25.97	19.67	15.46	15.46	12.89	12.89	1,753	2,046	2,391	2,852	18,417	21,494	31,285	19,337
RPL	0.90	-	-	-	0.59	0.59	0.49	0.49	1,753	2,046	2,391	2,852	546	(1,198)	(1,167)	(1,392)
SIGECO	3.87	4.00	4.00	3.87	7.15	7.15	5.95	5.95	1,753	2,046	2,391	2,852	(5,741)	(6,437)	(4,677)	(5,949)
SL-Dominion	8.06	2.74	2.74	2.74	2.47	2.47	2.06	2.06	1,753	2,046	2,391	2,852	9,809	553	1,630	1,945
Whiting Clean Energy	0.05	0.18	0.13	0.13	0.42	0.42	0.35	0.35	1,753	2,046	2,391	2,852	(643)	(478)	(512)	(611)
New units	0.34	0.48	0.87	1.74	5.45	5.45	4.54	4.54	1,753	2,046	2,391	2,852	(8,958)	(10,171)	(8,765)	(7,971)
Totals (existing and new)	137.72	133.65	123.64	108.00	108.94	109.08	90.89	90.89					50,459.08	50,558.30	78,570.28	49,116.51

Table B-3-3 Indiana EGUs Emissions Trading Costs-SO2-(Scenario #2 –IUG)

	SO2 Emissions (Thousand Tons)				SO2 Allocation (Thousand Tons)				SO2 Allowance Price (2005$/Ton)				SO2 Trading Cost (Thousand 2005$)			
Utility	2009	2012	2015	2020	2009	2012	2015	2020	2009	2012	2015	2020	2009	2012	2015	2020
AEP/I&M	96.03	97.33	97.33	80.46	46.96	46.96	32.87	32.87	988	1,153	1,348	1,749	48,484	58,076	86,893	83,214
Cinergy	86.32	88.28	85.79	70.74	74.02	74.02	51.82	51.82	988	1,153	1,348	1,749	12,145	16,439	45,798	33,093
Hoosier Energy	22.50	21.39	21.39	21.17	19.07	19.07	13.35	13.35	988	1,153	1,348	1,749	3,397	2,682	10,846	13,681
IKEC	41.75	10.46	10.46	10.46	26.01	26.01	18.21	18.21	988	1,153	1,348	1,749	15,550	(17,935)	(10,449)	(13,554)
IPL/AES	54.27	46.22	45.12	38.76	37.03	37.03	25.92	25.92	988	1,153	1,348	1,749	17,032	10,591	25,879	22,457
NIPSCO	67.18	67.18	67.18	70.81	26.08	26.08	18.26	18.26	988	1,153	1,348	1,749	40,600	47,381	65,944	91,888
RPL	4.57	-	-	-	4.60	4.60	3.22	3.22	988	1,153	1,348	1,749	(30)	(5,306)	(4,343)	(5,633)
SIGECO	12.87	16.90	16.92	16.71	15.94	15.94	11.16	11.16	988	1,153	1,348	1,749	(3,033)	1,105	7,763	9,697
SL-Dominion	8.87	9.56	9.56	9.56	4.88	4.88	3.42	3.42	988	1,153	1,348	1,749	3,945	5,395	8,281	10,742
	394.37	357.31	353.74	318.67	254.60	254.60	178.22	178.22	987.96	1152.97	1348.02	1748.56	138088.26	118427.65	236612.44	245584.32

Fuel –Switching Costs (Indiana EGUs –CAIR- Scenario #2 –IUG)

Methodology
Included in IDEM CAIR Grand Summary 12.07.05_s.xls is the change in fuel expenditures between the IEA Base and Policy Cases. As a first step, the unit level heat input for the IN fossil units from the 2012 and 2015 parsed results was multiplied by the fuel cost calculated for each unit provided in the spreadsheets "IEA Fuel Results Base Case 11.30.05_s" and "IEA Fuel Results Policy Case 11.30.05_s." The expenditures for each unit were summed to determine the total for IN. Since the 2020 parsed and fuel results are not available at this time, 2020 is assumed to be the same as 2015.

Expenditures on Coal
As shown in the "IDEM CAIR Grand Summary 12.07.05_s.xls" spreadsheet, expenditures on coal decreased under the Policy Case. The decreases in coal expenditures are not due to decreases in coal unit dispatch or in the individual coal prices, but in the coals the units are choosing to burn. Under the Policy Case, more units install scrubbers and switch to high sulfur coal, which is less expensive. This is the driver in the lower expenditures on coal.

Expenditures on Gas
As shown in the "IDEM CAIR Grand Summary 12.07.05_s.xls" spreadsheet, expenditures on gas increased under the Policy Case. Expenditures on gas increase due to increased gas fired generation, as well as, increased gas prices.

Table B-4.Indiana EGUs CAIR Fuel-switching Costs (Scenario #2 –IUG)

IUG Fuel Switching Summary

2012

Base Case

Sum of Total Cost (million 2005$)	
Fuel Type	Total
Coal	2,140
Gas	382
Grand Total	2,522

Policy Case

Sum of Total Cost (million 2005$)	
Fuel Type	Total
Coal	2,069
Gas	454
Grand Total	2,523

Delta (million 2005$)	
Coal	(71)
Gas	72

2015

Base Case

Sum of Total Cost (million 2005$)	
Fuel Type	Total
Coal	2,202
Gas	460
Grand Total	2,662

Policy Case

Sum of Total Cost (million 2005$)	
Fuel Type	Total
Coal	2,063
Gas	608
Grand Total	2,671

Delta (million 2005$)	
Coal	(139)
Gas	149

Table B-5 Indiana EGUs CAIR Switch-in Electricity Generating Costs (Scenario#2-IUG)

IUG Generation Switching Cost Summary			
CAIR/CAMR IPM Analysis			
Total Generation (GWh)	**2012**	**2015**	**2020**
Base	152,426	154,221	154,221
Policy	152,783	156,132	156,132
Difference	**357**	**1,911**	**1,911**
% Change	0.23%	1.24%	1.24%
Cost in $/MWh (1999$)	**2012**	**2015**	**2020**
Base	29.4	31.5	32.4
Policy	31.1	32.6	33.3
Cost in $/MWh (2005$)	**2012**	**2015**	**2020**
Base	35.3	37.8	38.9
Policy	37.3	39.1	40.0
Generation Cost (Million 2005$)	**2012**	**2015**	**2020**
Base	5,378	5,830	5,996
Policy	5,702	6,108	6,239
Delta	**$ 324**	**$ 278**	**$ 243**

Table B-6-1 Indiana EGUs CAIR Additional Electricity Generating Capacity Costs -2015 (Scenario #2 –IUG)

IPM projected unit (type)	Advanced Combined Cycle		
Construction cost			
Capacity (MW)	892.01		
Unit type (based on capacity)-Exhibit 4-9-U.S.EPA. IPM v.2.1.9	Advanced Combined Cycle		
Based on IEA input files (Costs based on AEO 2005)			
Heat rate (Btu/kWh)	6333		
All-in Capital cost (1999$/kW)	529		
Total capital cost (million 1999$)	472		
Capital charge rate -Exhibit 7-1, U.S. EPA IPM v. 2.1.9 -(%)	12.9		
Equipment life -years	30		
Capital recovery factor	0.132		
Annualized capital cost (million 1999$/yr)	62.51		
Fixed O&M cost (1999$/kW-yr)	9.60		
Kw--yr	892,013		
Fixed O&M cost (million 1999$/yr)	8.56		
Variable O&M cost (1999$/MWh)	1.63		
Capacity factor -based on IEA Results	75		
Electricity generation (MWh)	5,829,272		
Variable O&M cost (million 1999$/yr)	9.50		
Regional Adjustment Factors (Accounted for on line 8 above)	1.000		
Adjusted capital cost (million 1999$)	471.9		
Adjusted annualized capital cost (million 1999$)	62.5		
Fixed O&M cost (million 1999$/yr)	9.600		
Variable O&M cost (million 1999$/yr)	9.502		
Total annual cost (million 1999$/yr)	81.61		
Conversion 1999$ to 2005$	1.20		
Adjusted capital cost (million 1999$)	566.3		
Adjusted annualized capital cost (million 1999$)	75.0		
Fixed O&M cost (million 1999$/yr)	11.5		
Variable O&M cost (million 1999$/yr)	11.4		
Total annual cost (million 1999$/yr)	97.9		
Grand Total	CAIR Cost	Base Case Costs	Delta
Capital cost (million 2005$)	566.25	128.219	438.031
Annualized capital cost (million 2005$)	75.02	16.986	58.029
Annual O&M cost (million 2005$)	22.92	13.704	9.218
Total annual cost (million 2005$)	97.94	30.690	67.248

Table B-6-2 Indiana EGUs CAIR Additional Electricity Generating Capacity Costs -2015 Basecase (Scenario #2 –IUG)

IPM projected unit (type)	Advanced Combined Cycle
Construction cost	
Capacity (MW)	201.98
Unit type (based on capacity)-Exhibit 4-9-U.S.EPA. IPM v.2.1.9	Advanced Combined Cycle
Based on IEA input files (Costs based on AEO 2005)	
Heat rate (Btu/kWh)	6333
All-in Capital cost (1999$/kW)	529
Total capital cost (million 1999$)	107
Capital charge rate -Exhibit 7-1, U.S. EPA IPM v. 2.1.9 -(%)	12.9
Equipment life -years	30
Capital recovery factor	0.132
Annualized capital cost (million 1999$/yr)	14.16
Fixed O&M cost (1999$/kW-yr)	9.60
kW--yr	201,983
Fixed O&M cost (million 1999$/yr)	1.94
Variable O&M cost (1999$/MWh)	1.63
Capacity factor -based on IEA Results	63
Electricity generation (MWh)	1,116,474
Variable O&M cost (million 1999$/yr)	1.82
Regional Adjustment Factors (Accounted for on line 8 above)	1.000
Adjusted capital cost (million 1999$)	106.8
Adjusted annualized capital cost (million 1999$)	14.2
Fixed O&M cost (million 1999$/yr)	9.600
Variable O&M cost (million 1999$/yr)	1.820
Total annual cost (million 1999$/yr)	25.58
Conversion 1999$ to 2005$	1.20
Adjusted capital cost (million 1999$)	128.2
Adjusted annualized capital cost (million 1999$)	17.0
Fixed O&M cost (million 1999$/yr)	11.5
Variable O&M cost (million 1999$/yr)	2.2
Total annual cost (million 1999$/yr)	30.7
Grand Total	Base Case Cost
Capital cost (million 2005$)	128.22
Annualized capital cost (million 2005$)	16.99
Annual O&M cost (million 2005$)	13.70
Total annual cost (million 2005$)	30.69

Table B-6-3 Indiana EGUs CAIR Additional Electricity Generating Capacity Costs -2020 CAIR (Scenario #2 –IUG)

IPM projected unit (type)	Advanced Combined Cycle	Advanced Combustion Turbine	IGCC
Construction cost			
Capacity (MW)	1967.37	20.72	729.46
Unit type (based on capacity)-Exhibit 4-9- U.S.EPA. IPM v.2.1.9	Advanced Combined Cycle	Advanced Combustion Turbine	Integrated Gasification Combined Cycle
Based on IEA input files (Costs based on AEO 2005)			
Heat rate (Btu/kWh)	6333	8550	7200
All-in Capital cost (1999$/kW)	529	335	1348
Total capital cost (million 1999$)	1041	7	983
Capital charge rate -Exhibit 7-1, U.S. EPA IPM v. 2.1.9 -(%)	12.9	13.4	13.4
Equipment life -years	30	30	30
Capital recovery factor	0.132	0.137	0.137
Annualized capital cost (million 1999$/yr)	137.88	0.95	134.86
Fixed O&M cost (1999$/kW-yr)	9.60	8.60	31.60
Kw--yr	1,967,371	20,723	729,456
Fixed O&M cost (million 1999$/yr)	18.89	0.18	23.05
Variable O&M cost (1999$/MWh)	1.63	2.59	2.38
Capacity factor -based on IEA Results	75	7	87
Electricity generation (MWh)	12,856,690	12,526	5,533,767
Variable O&M cost (million 1999$/yr)	20.96	0.03	13.17
Regional Adjustment Factors (Accounted for on line 8 above)	1.000	1.000	1.000
Adjusted capital cost (million 1999$)	1040.7	6.9	983.3
Adjusted annualized capital cost (million 1999$)	137.9	1.0	134.9
Fixed O&M cost (million 1999$/yr)	9.600	8.600	31.600
Variable O&M cost (million 1999$/yr)	20.956	0.032	13.170
Total annual cost (million 1999$/yr)	168.43	9.58	179.63
Conversion 1999$ to 2005$	1.20	1.20	1.20
Adjusted capital cost (million 1999$)	1248.9	8.3	1180.0
Adjusted annualized capital cost (million 1999$)	165.5	1.1	161.8
Fixed O&M cost (million 1999$/yr)	11.5	10.3	37.9
Variable O&M cost (million 1999$/yr)	25.1	0.0	15.8
Total annual cost (million 1999$/yr)	202.1	11.5	215.6
Grand Total	**CAIR Cost**	**Base Case Costs**	**Delta**
Capital cost (million 2005$)	2437.19	3112.05	-674.87
Annualized capital cost (million 2005$)	328.43	412.33	-83.90
Annual O&M cost (million 2005$)	100.75	117.84	-17.09
Total annual cost (million 2005$)	429.18	530.18	-101.00

Table B-6-4 Indiana EGUs CAIR Additional Electricity Generating Capacity Costs -2020 Basecase (Scenario #2 –IUG)

IPM projected unit (type)	Advanced Combined Cycle	Advanced Combustion Turbine	Coal steam
Construction cost			
Capacity (MW)	201.98	29.48	2028.38
Unit type (based on capacity)-Exhibit 4-9-U.S.EPA. IPM v.2.1.9	Advanced Combined Cycle	Advanced Combustion Turbine	Conventional Pulverized Coal
Based on IEA input files (Costs based on AEO 2005)			
Heat rate (Btu/kWh)	6333	8550	8600
All-in Capital cost (1999$/kW)	529	335	1221
Total capital cost (million 1999$)	107	10	2477
Capital charge rate -Exhibit 7-1, U.S. EPA IPM v. 2.1.9 -(%)	12.9	13.4	12.9
Equipment life -years	30	30	30
Capital recovery factor	0.132	0.137	0.132
Annualized capital cost (million 1999$/yr)	14.16	1.35	328.10
Fixed O&M cost (1999$/kW-yr)	9.60	8.60	22.50
Kw--yr	201,983	29,476	2,028,383
Fixed O&M cost (million 1999$/yr)	1.94	0.25	45.64
Variable O&M cost (1999$/MWh)	1.63	2.59	3.75
Capacity factor -based on IEA Results	63	7	84
Electricity generation (MWh)	1,116,474	17,817	14,836,809
Variable O&M cost (million 1999$/yr)	1.82	0.05	55.64
Regional Adjustment Factors (Accounted for on line 8 above)	1.000	1.000	1.000
Adjusted capital cost (million 1999$)	106.8	9.9	2476.7
Adjusted annualized capital cost (million 1999$)	14.2	1.4	328.1
Fixed O&M cost (million 1999$/yr)	9.600	8.600	22.500
Variable O&M cost (million 1999$/yr)	1.820	0.046	55.638
Total annual cost (million 1999$/yr)	25.58	10.00	406.24
Conversion 1999$ to 2005$	1.20	1.20	1.20
Adjusted capital cost (million 1999$)	128.2	11.8	2972.0
Adjusted annualized capital cost (million 1999$)	17.0	1.6	393.7
Fixed O&M cost (million 1999$/yr)	11.5	10.3	27.0
Variable O&M cost (million 1999$/yr)	2.2	0.1	66.8
Total annual cost (million 1999$/yr)	30.7	12.0	487.5
Grand Total	Base Case Cost		
Capital cost (million 2005$)	3112.05		
Annualized capital cost (million 2005$)	412.33		
Annual O&M cost (million 2005$)	117.84		
Total annual cost (million 2005$)	530.18		

Appendix C
State Utility Forecasting Group Analysis

The Projected Impacts of the Clean Air Interstate Rule on Electricity Prices in Indiana

State Utility Forecasting Group, Purdue University

1. Introduction

This paper examines the impact of various nitrogen oxides (NO_x) and sulfur dioxide (SO_2) emission control scenarios on the projected prices of electricity in the state of Indiana. The scenarios represent different methods for achieving the reductions in NO_x and SO_2 emissions mandated by the United States Environmental Protection Agency (EPA) under its Clean Air Interstate Rule (CAIR). The analyses were performed using a traditional regulation forecasting model that equilibrates between price and demand. Thus, the effects of price changes on demand levels were captured. Price impacts are presented at an overall average level as well as by customer class. The impacts of various assumptions made in the selection of the scenarios are analyzed. This paper does not attempt to compare the cost of emissions controls to the benefits of reduced emissions.

The price projections here are an average retail regulated rate paid by the consumer. Therefore, non-utility generators are not included. While the State Utility Forecasting Group (SUFG) models both the investor-owned not-for-profit utilities in the state, the prices for the not-for-profit utilities are only known at the wholesale level (i.e., the price at which the utility sells to its member cooperative or municipal member). Thus, the price projections are only for the investor-owned utilities.

The emissions control scenarios included here were developed using a different set of electricity usage growth assumptions than those that SUFG uses for its own projections. Since some of the costs modeled are included per unit of output for the generator, this results in total costs being somewhat different from those in the original scenarios. The results presented here are subject to a number of assumptions regarding the compliance strategies used by the utilities to meet the CAIR standards, the capital and operating costs associated with emissions control devices, the future market price of emissions allowances, and any reduction in overall plant efficiency resulting from the addition of pollution control devices. Two alternative scenarios are presented that were developed using different sets of assumptions.

2. Background

Reductions in the emissions levels of NO_x and SO_2 were called for by the Clean Air Act Amendments of 1990. Both NO_x and SO_2 are considered to be the primary causes of acid rain. Acid rain affects the acidity of soil and water, which can be harmful to plants and aquatic animals. Acid rain can also damage buildings and other structures and reduce visibility. Furthermore, NO_x reacts with volatile organic compounds in the presence of heat and sunlight to form ozone. In the upper atmosphere, ozone occurs naturally and shields the earth from the sun's harmful ultraviolet rays. When found closer to the ground, however, ozone poses significant risk to human and plant health. Exposure to ozone irritates human lungs, reducing lung function and exacerbating respiratory diseases such as asthma. Ground-level ozone interferes with the ability of plants to produce and store food, so that growth, reproduction and overall plant health are compromised. It is also a major component of urban smog [1].

Table 1 summarizes the main legislation on which the EPA acts. In conjunction with United States laws, EPA issues regulations regarding various emissions and timelines for meeting the regulations. The regulations are often legally challenged and revised as needed in response to court decisions.

1963 Clean Air Act (Original)	
1967 Clean Air Act Amendments	• Requires New Source Performance Standards (NSPS)
1970 Clean Air Act Amendments	• Requires National Ambient Air Quality Standards (NAAQS) • Required State Implementation Plans (SIPs) to achieve NAAQS • Requires National Emissions Standards for Hazardous Air Pollutants (NESHAPs) • Mandates New Source Reviews in non-attainment areas
1977 Clean Air Act Amendments	• Prevention of Significant Deterioration (PSD) of air quality
1990 Clean Air Act Amendments (complete rewrite of the old Clean Air Act)	• Revises the Titles and requires EPA to issue 175 new regulations, 30 guidance documents, and 22 reports • Requires EPA to establish interstate air pollution transport regions • Mandates maximum achievable control technology (MACT) for 189 airborne toxics by 2003 • Mandates reduction of SO_2 emissions by 8.9 million tons per year by 2000 • Requires EPA to establish an allowance trading and tracking system for SO_2 emissions • Mandates permit and emissions fee system for acid rain emissions • Basis for regulations including two phase SO_2 reduction program, Title IV NO_x reductions, NAAQS NO_x reductions, 2005 Clean Air Interstate Rule, and 2005 Clean Air Mercury Rule

Table 1. Major U.S. Laws and Regulations Regarding Air Emissions [2]

In March 2005, the EPA promulgated new regulations effecting electric power plant emissions. CAIR lowers allowed emissions of SO_2 and NOx by roughly 56 percent and 68 percent, respectively, from currently allowed levels. CAIR is a cap and trade type program for SO_2 and NOx emissions with new emissions caps to be fully implemented in two phases. The first phase takes place in 2009 (NOx) and 2010 (SO_2), and the second phase in 2015 for both SO_2 and NOx. At nearly the same time, the EPA also finalized a rule for mercury emissions called the Clean Air Mercury Rule (CAMR). The mercury rule is also a cap and trade, two-phase rule and is projected to reduce mercury emissions from electric power plants by approximately 70 percent by 2018. The first phase of CAMR depends upon the co-benefits of control measures implemented under phase one of CAIR, while the second phase is expected to require additional mercury specific control measures. This report focuses only on CAIR and does not attempt to measure the impact of the second phase mercury restrictions of CAMR.

The compliance options available to fossil generators fall into four distinct categories: emission control technologies, fuel switching, the use of emission allowances, and the retirement of affected generating units. There are two main categories of emission control technologies, combustion control and post-combustion technologies. Low NO_x burners, which work at the combustion stage, were installed in many generating units to meet compliance with the Clean Air Act Amendments of 1990. Other forms of combustion control technologies include flue gas recirculation, steam or water injection, and staged combustion. Post-combustion control is done using either catalytic or non-catalytic reduction for NO_x emissions and flue gas desulfurization systems, also known as scrubbers, for SO_2.

In Selective Catalytic Reduction (SCR) systems, ammonia vapor is used as the reducing agent and is injected into the flue gas stream downstream of the boiler. The mixture passes over a catalyst, reducing the NO_x to nitrogen and water. SCR is one of the few technologies capable of removing high levels (80% or more) of NO_x from the flue gas of coal-fired generators commonly used in the U.S. utility industry.

In Selective Non-Catalytic Reduction (SNCR) systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. Emissions of NO_x can be reduced by 30% for large boilers to 50% for smaller boilers. The NO_x and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. Both ammonia and urea SNCR processes require three or four times as much reagent as SCR systems to achieve similar NO_x reductions.

Low NO_x burners reduce NO_x formation in the combustion stage by reducing flame temperature and local oxygen concentrations. This is accomplished by controlling the fuel and air mixture to alter the size and shape of the flame.

Flue gas desulfurization (FGD) systems inject a sorbent, often crushed limestone, into the exhaust stream. The sorbent reacts with the SO_2, thus removing it from the exhaust gas and producing gypsum.

Fuel switching involves replacing coal or oil as a source of fuel with natural gas to lower NO_x emissions or switching to a lower sulfur coal to reduce SO_2 emissions. Fuel switching can involve a complete switch to a different fuel or partial fuel switching. Partial fuel switching can be accomplished in a number of ways, such as seasonal switching and natural gas reburn for NO_x and fuel blending for SO_2. Seasonal switching involves using natural gas as the fuel source during the summer, which is the primary ozone season. Natural gas reburn involves co-firing a small amount of natural gas (10-20%) with the other fuel source. The costs associated with fuel switching vary greatly depending on the boiler size and design as well as access to natural gas or low sulfur coal. It may result in higher fuel costs.

Retirement may be an option for older, smaller generating units where the cost associated with installing an emission control device or switching to a different fuel exceeds the expected economic benefit of keeping the unit in operation.

Due to its large reserves of Illinois Basin coal, Indiana depends quite heavily on coal as a fuel source for electricity generation. 79 percent of the electric power generating capacity in the state is coal-fired and over 93 percent of the electricity generated there is derived from coal. As a result of this reliance on coal, as of 2002 Indiana ranked second in the United States in the amount of NO_x emitted annually and third in SO_2 [3]. Therefore, the CAIR emissions reduction regulations will significantly affect Indiana.

The analyses were performed for the five investor-owned utilities (Indiana Michigan Power Company, Indianapolis Power & Light Company, Northern Indiana Public Service Company, Cinergy, and Southern Indiana Gas & Electric Company) and three major not-for-profit entities (Hoosier Energy Rural Electric Cooperative, Indiana Municipal Power Agency, and Wabash Valley Power Association) that supply electric power to Indiana customers. The statewide electricity prices reported here were determined using energy-weighted averages of the five investor-owned utilities for the residential, commercial, and industrial sectors as well as for all customer groups combined.

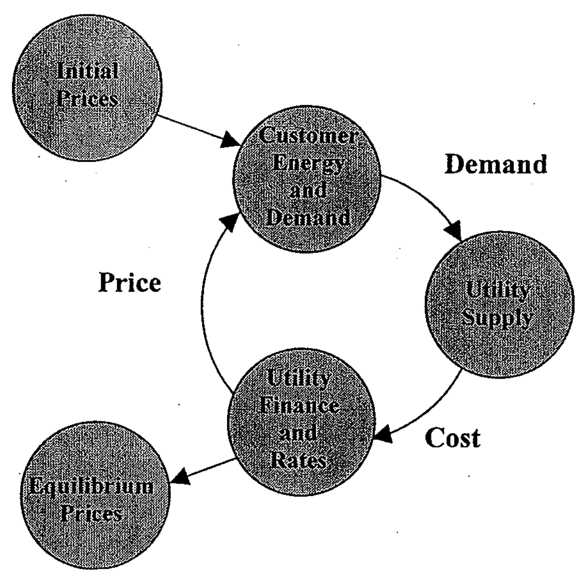
3. Methodology

To determine the impacts on prices of various levels of NO_x and SO_2 emissions restrictions, scenarios were analyzed using a traditional regulation forecasting model developed by the State Utility Forecasting Group (SUFG) [4]. This model projects electric energy sales and peak demand as well as future electric rates given a set of exogenous factors. These factors describe the future of the Indiana economy and prices of fuels that compete with electricity in providing end-use services or are used to generate electricity. Combinations of econometric and end-use models are used to project electricity use for the major customer groups -- residential, commercial, and industrial. The modeling system predicts future electricity rates for these sectors by simulating the cost-of-service based rate structure traditionally used to determine rates under regulation. In this type of rate structure, ratepayers are typically allocated a portion of capital costs and fixed operating costs based on the customers' service requirements and are assigned fuel and other variable operating costs based upon the electric utility's out-of-pocket operating costs.

The fuel price and economic activity forecasts that form the primary drivers of these models were not changed from one scenario to another to maintain consistency in the analyses. The other major model driver, the price of electricity, varies according to the results of the scenario. Therefore, any changes in customer demand from one scenario to another result entirely from the emissions reduction requirements.

Using an initial set of electricity prices for each utility, a forecast of customer demands is developed. These demands are then sent through a generation dispatch model to determine the operating costs associated with meeting the demands. The operating costs and demands are sent to a utility finance and rates model that determines a new set of electricity prices for each utility. These new prices are sent to the energy and demand model and a new iteration begins. The process is repeated until an equilibrium state is reached where prices and demands do not vary from one iteration to the next for each year of the analyses. Thus, the model includes a feedback mechanism that equilibrates energy and demand simultaneously with electric rates (Figure 1).

Figure 1. Cost-Price-Demand Feedback Loop



In the later years of the analyses, new resources are needed for the utilities to adequately meet the load. This is accomplished through another iterative process with the costs associated with acquiring these resources (either through purchases, construction or conservation) impacting the rates accordingly. Since the demand levels in each scenario differ due to the price impacts, the amount of new requirements changes also. However, the criteria for determining resource requirements are held constant to ensure consistency between scenarios.

Emissions control technologies will affect the price of electricity in several ways. In this modeling system, the capital cost of equipment is captured in the rates and finance model, using a traditional regulated rate of return. The operating cost impacts are captured in the generation dispatch model. These impacts include changes in fuel costs resulting from changes in overall plant efficiency, increased maintenance costs, and changes to generation unit availability, for both emissions reduction equipment installation and maintenance.

4. Emissions Control Scenarios

SUFG analyzed two different scenarios for complying with CAIR emissions reductions: one developed by the Indiana Department of Environmental Management (IDEM) and one from the Indiana Utility Group (IUG). The scenarios use different combinations of compliance options (new equipment, fuel switching, allowance trading, and generating unit retirement). Options vary between the scenarios in terms of capital cost, operating cost, and the year implemented. Table 2 lists the amount of capacity affected and the installation costs for both scenarios.

Scenario	Capacity Affected (MW)			Installation Costs (million 2005$)
	SNCR	SCR	FGD	
IDEM	180	2611	4686	1617
IUG	0	2508	3698	1976

Table 2. Capacity Affected and Installation Costs

In addition to the scenario assumptions, SUFG made further assumptions in order to perform this analysis using SUFG's traditional (or regulated) modeling structure. These assumptions pertain to future capital costs for retrofit control equipment, expenditure streams for retrofit equipment installation, and the timing of retrofit installations. SUFG feels these assumptions are reasonable, but also recognizes that they should be subject to further refinement in subsequent analyses, as further information becomes available.

SUFG has assumed that capital costs for emissions control equipment will escalate at an annual rate of 2.5% per year from the 2005 dollar base year estimates provided by IDEM and IUG. While this escalation rate assumption is open to debate, it is consistent with the assumptions SUFG employed in preparing the 2005 SUFG report *Indiana Electricity Projections: The 2005 Forecast*, which is used as a base case in estimation of the additional costs to ratepayers of further emissions reductions.

SUFG has assumed that NO_x and SO_2 retrofit control equipment for all affected generation units will be installed over an 18-month period for all retrofit options including SNCR, SCR, and FGD. SUFG has further assumed that the stream of expenditures for such retrofit is evenly divided across this 18-month period. Since the SUFG model is an annual model, SUFG has allocated the control retrofit costs to specific years based upon the assumed on-line date of the control equipment. Capital costs are escalated from the 2003 dollar base year to the middle of the 18-month construction period and then allocated to specific years. For example, if a control device is assumed to be on-line in the spring of 2009, capital cost are escalated from 2003 dollars to mid-year 2008 dollars and then allocated to 2007 expenditures (1/6 of the total), 2008 (2/3 of the total), and 2009 expenditures (1/6 of the total). The same procedure is used for fall installations, with capital escalation through the beginning of the on-line year and capital cost allocations of 50 percent (prior year) and 50 percent (on-line year). Fixed operations and maintenance costs are assumed to be incurred immediately following the installation of a control device even if the control is installed prior to the compliance requirement date.

The 18-month installation period used in these analyses does not represent the total time needed for planning, design and engineering. These processes take a considerable amount of time before the actual physical construction begins. Likewise, the 18-month time period does not represent the time that the generating unit must be taken out of service for the installation process. The downtimes used in these analyses were 2 weeks for SNCR and 8 weeks for SCR and FGD installations.

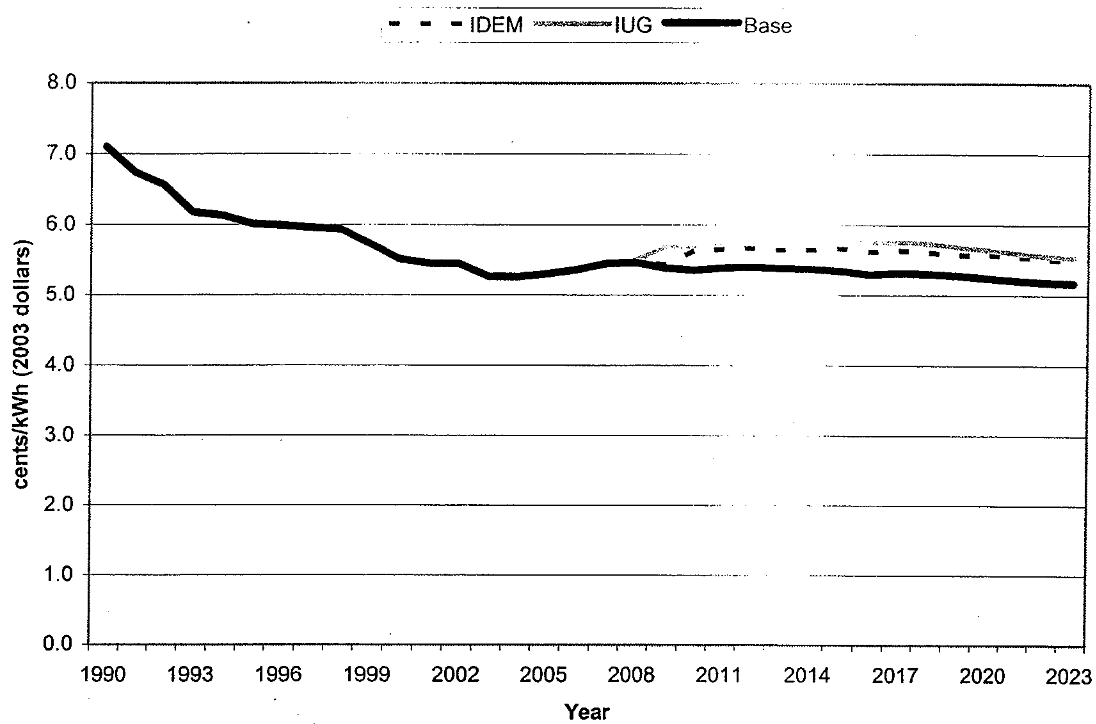
Since detailed installation schedules for emissions control devices were unavailable, SUFG assigned installation dates for all retrofit controls. The procedure used to assign on-line dates is somewhat arbitrary and should be refined in future analysis. SUFG assigned on-line dates by attempting to minimize the capacity off-line for retrofits and delaying retrofits until required for compliance on an individual utility basis. For example, if a utility is required to retrofit two large coal units, the units were assigned retrofit periods of Fall and Spring; three large units were assigned retrofit periods of Spring, Fall, and Spring and so forth. A more reasonable allocation of retrofit dates would explicitly incorporate the utilities' maintenance schedules and attempt to overlay final installation with major maintenance periods as well as attempt to coordinate installation outages across utilities where possible.

While these analyses capture the price effects of retrofit outages, they do not address the question of whether the reliability of the system will be impaired. In 2001, SUFG conducted a study for the NO_x retrofits associated with the National Ambient Air Quality Standards, in which it was determined that the state would likely have sufficient capacity to handle the necessary retrofits [5]. It is uncertain whether that conclusion would be reached for the first phase of CAIR retrofits. Since the second phase of CAIR does not take place until 2015, sufficient lead time should be available for utilities to complete the retrofits without compromising system reliability.

5. Results

SUFG's projections of future electricity rates for the two emissions control scenarios are compared with a base case from SUFG's 2005 report *Indiana Electricity Projections: The 2005 Forecast* in Figure 2. The base case was constructed assuming no emissions controls from CAIR, so the scenarios represent incremental changes to the base case. The rate projections in Figure 2 are an energy-weighted average for the residential, commercial, and industrial sectors for the five Indiana investor-owned utilities. The figure illustrates that average retail rates would be expected to increase 5 to 8.5 percent, depending on the time period and scenario.

Figure 2. Comparison of Rates by Scenario



The effect on the individual rate classes is similar to the average but differs somewhat due to cost-of-service allocation of capital recovery and fixed operating costs. The differences across customer classes for the scenarios for representative years are presented in Tables 3 through 5. Rates are provided in 2003 dollars in order to be consistent with the base scenario from SUFG's 2005 forecast.

	Base Scenario (¢/kWh)	IDEM Scenario		IUG Scenario	
		Rate (¢/kWh)	Change	Rate (¢/kWh)	Change
Residential	6.79	7.11	+4.65 %	7.19	+5.92 %
Commercial	5.83	6.10	+4.66 %	6.15	+5.60 %
Industrial	4.10	4.34	+5.84 %	4.39	+7.11 %
Average	5.35	5.63	+5.16 %	5.70	+6.44 %

Table 3. Rate Comparisons by Sector in 2010 (in 2003 dollars)

	Base Scenario (¢/kWh)	IDEM Scenario		IUG Scenario	
		Rate (¢/kWh)	Change	Rate (¢/kWh)	Change
Residential	6.62	6.99	+5.67 %	7.13	+7.81 %

Commercial	5.74	6.05	+5.46 %	6.18	+7.61 %
Industrial	4.23	4.48	+6.03 %	4.61	+9.02 %
Average	5.35	5.67	+5.97 %	5.80	+8.55 %

Table 4. Rate Comparisons by Sector in 2015 (in 2003 dollars)

	Base Scenario (¢/kWh)	IDEM Scenario		IUG Scenario	
		Rate (¢/kWh)	Change	Rate (¢/kWh)	Change
Residential	6.34	6.74	+6.35 %	6.80	+7.27 %
Commercial	5.56	5.88	+5.83 %	5.94	+6.90 %
Industrial	4.29	4.56	+6.15 %	4.62	+7.69 %
Average	5.25	5.58	+6.34 %	5.65	+7.63 %

Table 5. Rate Comparisons by Sector in 2020 (in 2003 dollars)

The rate increase in ¢/kWh tends to be slightly higher in the residential sector and slightly lower in the industrial sector, with the commercial sector close to the average. In terms of a percentage increase, the industrial sector sees a higher increase due to the lower initial rates.

The difference between SUFG's base case and the IDEM scenario is about 0.32 ¢/kWh. Roughly 0.17 cents or slightly more than one half of the increase is due to increased out-of-pocket operating costs and the remainder of the increase, about 0.15 ¢/kWh, is due to recovery of equipment installation costs and fixed operating costs. For the IUG scenario, the price differential follows a similar pattern with a difference of about 0.45 ¢/kWh, of which about 45 percent is due to increased out-of-pocket operating costs and the remainder is due to recovery of equipment installation costs and fixed operating costs.

6. Summary and Conclusions

This paper presented the projected impacts of NO_x and SO_2 emissions reductions on Indiana electricity prices. Scenario analyses were performed using the SUFG traditional regulation modeling system. These scenarios depict various combinations of control technologies, such as SCR, SNCR, and FGD.

The results of these scenarios indicate that electricity prices can be expected to increase due to NO_x and SO_2 emissions reductions. Under the IDEM scenario, prices are expected to increase by roughly 5 to 6.5 percent due to the more stringent emissions controls of CAIR. In the IUG scenario, prices are expected to increase by roughly 6.5 to 8.5 percent. Finally, the increase in electricity rates resulting from NO_x emissions reductions is felt by all three customer classes, with the increase to residential rates being slightly greater (and the increase to industrial rates being slightly lower) than the increase to commercial rates.

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